TransAlta Corporation
Third Quarter Report for 2017

Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2017 and 2016, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2016 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 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 publically accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Sept. 30, 2017. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 31, 2017. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov**, and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.

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 (loss) in our Condensed Consolidated Statements of Earnings (Loss) for the three and nine months ended Sept. 30, 2017, and 2016. 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. Earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable EBITDA, Funds from Operations ("FFO"), and "Free Cash Flow" ("FCF") are non-IFRS measures. See the Reconciliation of Non-IFRS Measures and Discussion of Segmented Comparable Results sections of this MD&A for additional information.

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are presented for general information purposes only and not as specific investment advice. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were 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", "believe", "expect", "anticipate", "intend", "plan", "project", "forecast", "foresee", "potential", "enable", "continue", or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to: our business and anticipated future financial performance; our success in executing on our growth projects; the timing of the construction and commissioning of projects under development, including, the Brazeau Pumped Storage Project, Kent Hills 3 Wind Project, the Antelope Coulee Wind project, Garden Plain wind project, Tono Solar Project, and the conversion of our Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation, and their attendant costs and sources of funding; the retirement of Sundance Unit 1 and mothballing of Sundance Unit 2; the changes to capacity and emissions following the conversion to gas generation of Sundance Units 3 to 6 and Keephills Units 1 and 2; the compensation expected from the Balancing Pool in connection with the termination of the Alberta Power Purchase Arrangements; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; expected decommissioning costs; the acquisition by Fortescue Metals Group Ltd. ("FMG") (as defined below) of the Solomon plant, including the timing and associated acquisition price; the section titled "2017 Financial Outlook"; the ability of Sundance Unit 2 to qualify for the 2019 capacity market auction; coal supply constraints for our facilities in Alberta and their impact on our mining costs and power generation at our Sundance coal-fired generating units 1 to 6 and Keephills units 1 to 3; the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses; dividend payout ratio; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2017 comparable EBITDA, FFO, FCF, and expected sustaining capital expenditures); expectations in respect of financial ratios and targets and the timing associated with meeting such targets (including FFO before interest to adjusted interest coverage, adjusted FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); Canadian Coal Fleet availability; the anticipated financial impact to be realized from the commercial operation of the South Hedland power project; the Corporation's plans and strategies relating to repositioning its capital structure and strengthening its balance sheet and the anticipated debt reductions during 2017 and beyond; expected governmental regulatory regimes and legislation including the Government of Alberta's intended shift to a capacity market, renewable auctions and intention to support coal-to-gas conversions, Climate Leadership Plan, the expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected results and impact of the Off-Coal Agreement ("OCA") with the Government of Alberta on our business and financial performance; estimates of fuel supply and demand conditions and the costs of procuring fuel; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; power prices in Alberta, Ontario, and Pacific Northwest for the remainder of 2017; expected financing of our capital expenditures; the anticipated financial impact of increased carbon prices (including under the existing Specified Gas Emitters Regulation) ("SGER") in Alberta; expectations in respect of our environmental initiatives; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets on reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar, the Australian dollar, and other currencies in which we do business; our exposure to liquidity risk; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; expected cost savings and payback periods following the implementation of our efficiency and productivity initiatives, including Project Greenlight; the estimated contribution of Energy Marketing activities to gross margin; expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of

TransAlta Renewables; the refinancing of our upcoming debt maturities over the next two years; expectations regarding our de-leveraging strategy; expectations in respect of our community initiatives; impacts of future IFRS standards and the timing of the implementation of such standards; and amendments or interpretations by accounting standard setters prior to initial adoption of those standards.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices, our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, sun, or wind required to operate our facilities; natural or man-made disasters; the threat of terrorism and cyberattacks and our ability to manage such attacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing and the ability to access financing at a reasonable cost and on reasonable terms; our ability to fund our growth projects; our ability to maintain our investment grade credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; outcomes of legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays or changes in costs in the construction and commissioning of the Kent Hills 3 wind project; and the maintenance or adoption of enabling regulatory frameworks or the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives, including as it pertains to coal-to-gas conversions.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and under the heading “Risk Factors” in our 2017 Annual Information Form for the fiscal year ended Dec. 31, 2016.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. 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 events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

Highlights
Consolidated Financial Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Revenues	**588**	620	**1,669**	1,680
Net earnings (loss) attributable to common shareholders	**(27)**	(12)	**(45)**	56
Cash flow from operating activities	**201**	228	**545**	622
Comparable EBITDA[(1)]	**245**	244	**787**	771
FFO[(1)]	**196**	163	**585**	535
FCF[(1)]	**99**	55	**224**	200
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.09)**	(0.04)	**(0.16)**	0.19
FFO per share[(1)]	**0.68**	0.57	**2.03**	1.86
FCF per share[(1)]	**0.34**	0.19	**0.78**	0.69
Dividends declared per common share	**0.04**	0.04	**0.08**	0.12

As at	**Sept. 30, 2017**	Dec. 31, 2016
Total assets	**10,361**	10,996
Net debt[(2)]	**3,667**	3,893
Total long-term liabilities	**4,324**	5,116

Comparable EBITDA was up $1 million for the three months ended Sept. 30, 2017, compared to the same period in 2016. During the quarter, we benefited from lower transportation costs on coal and higher prices on merchant and contracted revenues at US Coal, and we commissioned the South Hedland power project in Australia. Lower wind resources reduced revenue at our Wind and Solar operations during the quarter, while Energy Marketing returned to normal margins relative to the same period in 2016. At Canadian Coal, higher fuel costs caused by a higher expected strip ratio, lower equipment availability and lower productivity at our mine, and lower prices due to the rolling off of certain hedges, negatively impacted our results. This was partially offset by the Off-Coal Agreement ("OCA") payment from the Government of Alberta and higher prices on our non-contracted generation in Alberta.

Comparable EBITDA was up $16 million for the nine months ended Sept. 30, 2017, compared to the same period in 2016, due to the settlement of the contract indexation dispute with the Ontario Electricity Financial Corporation ("OEFC") relating to the Ottawa and Windsor generating facilities, totalling $34 million in the second quarter and the positive impact of the early shut down of our Mississauga gas plant in Ontario. We also commissioned the South Hedland power project during the third quarter. At US Coal, lower transportation costs on coal, favourable mark-to-market on economic hedges that do not qualify for hedge accounting and higher merchant and contracted revenues contributed to higher comparable EBITDA. Energy Marketing was impacted by unusual weather in the Northeast and the Pacific Northwest and delivered below expected performance in the first quarter of 2017. Our Canadian Coal results were impacted by higher fuel and purchased power due to higher coal costs caused by a higher strip ratio, lower equipment availability at our mine, and higher environmental compliance costs in 2017. Lower prices due to the rolling off of certain hedges also negatively impacted our results. This was partially offset by the OCA payments and higher prices on our non-contracted generation.

FFO for the three and nine months ended Sept. 30, 2017 was up $33 million and $50 million, respectively, compared to the same periods in 2016, driven by higher comparable EBITDA. The timing of sustaining capital expenditures and higher distributions paid to subsidiaries' non-controlling interests negatively impacted our FCF during the second quarter of 2017.

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(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) Net debt includes current portion, amounts due under credit facilities, long-term debt, tax equity, and finance lease obligations, net of 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.

Reported net loss attributable to common shareholders for the third quarter of 2017 was $27 million ($0.09 loss per share) compared to a $12 million net loss ($0.04 loss per share) during the same period in 2016. Year-to-date, reported net earnings were down $101 million ($0.35 loss per share) due to lower EBITDA, a $20 million impairment charge recognized in the second quarter as a result of our decision to early retire Sundance Unit 1 at the end of 2017, and higher depreciation of $57 million due to the shortening of the useful lives of Keephills 3, Genesee 3, and, to a lesser extent, Sundance Unit 1. The $30 million of OCA payments recognized year-to-date partially offset these impacts.

Segmented Comparable EBITDA Results

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Comparable EBITDA				
Canadian Coal	**82**	99	**258**	295
U.S. Coal	**24**	13	**68**	27
Canadian Gas	**56**	53	**201**	174
Australian Gas	**45**	32	**108**	96
Wind and Solar	**26**	32	**136**	129
Hydro	**19**	19	**61**	62
Energy Marketing	**12**	10	**20**	39
Corporate	**(19)**	(14)	**(65)**	(51)
Total comparable EBITDA	**245**	244	**787**	771

Significant Events

During the year, we continued to work on strengthening our balance sheet, improving our operating performance, and progressing our transition to clean power generation through the following initiatives:

- On July 28, 2017, we achieved commercial operation on our South Hedland power project. The project is expected to generate approximately $80 million of comparable EBITDA annually. See the Significant and Subsequent Events section of this MD&A for further details. On Aug. 1, 2017, TransAlta Renewables converted the Class B shares we owned into common shares, and also increased their monthly dividend by approximately 7 per cent.
- On Sept. 18, 2017, we received formal notice from the Balancing Pool for the termination of the Sundance B and C Power Purchase Arrangements ("Sundance PPAs"), effective March 31, 2018. See the Significant and Subsequent Events section of this MD&A for further details.
- During the second quarter, we entered into a long-term contract for the 17.25 MW Kent Hills 3 expansion project located in New Brunswick, which is expected to begin commercial operation in the fall of 2018. On Oct. 2, 2017, TransAlta Renewables' indirect majority-owned subsidiary, Kent Hills Wind LP, closed a $260 million project level financing. The bonds issued as part of this financing are amortizing and bear interest at an annual rate of 4.454 per cent, payable quarterly and maturing Nov. 30, 2033. See the Significant and Subsequent Events section of this MD&A for further details.
- On July 24, 2017, TransAlta Renewables entered into a syndicated credit agreement giving it access to $500 million in direct borrowings, and we reduced our syndicated credit facility by the same amount. Our consolidated liquidity remains unchanged. Both facilities expire in 2021.
- In March 2017, we closed the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale reduced our merchant exposure in Alberta and the proceeds were used to repay debt.
- In April 2017, we announced the acceleration of our transition to gas and renewables generation with the retirement of Sundance Unit 1 and the mothballing of Sundance Unit 2 at the end of 2017, and the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation between 2021 to 2023. The retirement of Sundance Unit 1 and mothballing of Sundance Unit 2 is not expected to have a material impact on our forecasted cash flow for 2018 and 2019. We received approval to extend the life of Sundance Unit 2 to the end of 2021 on coal. This unit will be available to qualify for the capacity market auctions in the 2019 timeframe.
- During the second quarter, we settled the contract indexation dispute with the OEFC. The settlement consisted of a $34 million payment by the OEFC to TransAlta.

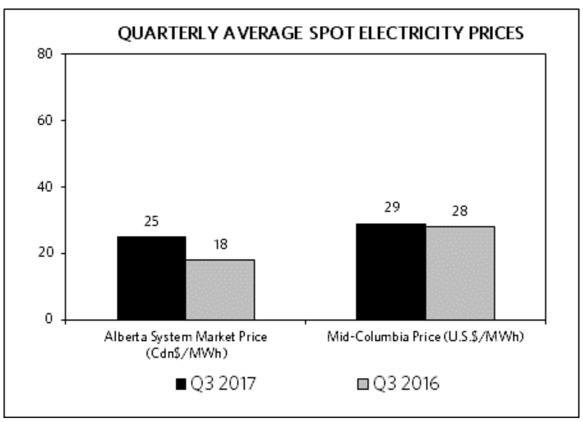
Adjusted Availability and Production

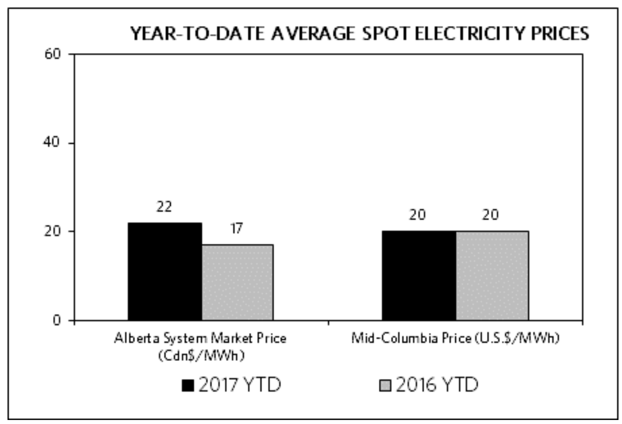
Adjusted availability for the three and nine months ended Sept. 30, 2017 was 86.5 per cent and 86.3 per cent, respectively, compared to 89 per cent and 89.3 per cent for the same periods in 2016. During the quarter and year-to-date, the main causes of the decreases were higher outages and derates at Canadian Coal and planned maintenance at our Sarnia facility. Windsor's base to cycling conversion project also impacted the year-to-date availability. Lower availability had a minimal impact on our results due to current low prices in Alberta, the Pacific Northwest, and Ontario.

Production for the three and nine months ended Sept. 30, 2017 was 9,767 GWh and 26,526 GWh, respectively, compared to 10,769 GWh and 27,533 GWh for the same periods in 2016. The cessation of operations at our Mississauga gas plant effective Jan. 1, 2017, higher outages and derates at Canadian Coal, and lower wind resources were the main drivers of the production decrease in the third quarter of 2017. This was partially offset by higher generation from Australia due to the commissioning of South Hedland and stronger customer demand. On a year-to-date basis, US Coal had higher production compared to 2016 as a result of lower economic dispatching in the first quarter of 2017 due to slightly higher prices. Higher water resources at Hydro also contributed to higher production in 2017. Lower production at Canadian Coal was due to higher outages and derates. In accordance with the terms of Mississauga's new contract with Ontario's Independent Electricity System Operator ("IESO"), we continue to receive monthly capacity payments from the IESO until Dec. 31, 2018.

Electricity Prices

In Alberta, the average spot electricity prices for the three and nine months ended Sept. 30, 2017 increased compared to the same periods in 2016 as environmental compliance costs increased marginal costs to producers. Higher summer temperatures and low thermal availability also impacted prices. In the Pacific Northwest, during the third quarter of 2017, an exceptionally hot and dry summer resulted in stronger third quarter 2017 prices compared to 2016 and offset the lower prices in the second quarter of 2017 caused by abundant water resources.





Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for the amount of 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 generated by our business, before changes in working capital, 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 as to not distort FFO and FCF with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Cash flow from operating activities	**201**	228	**545**	622
Change in non-cash operating working capital balances	**(21)**	(80)	**(7)**	(134)
Cash flow from operations before changes in working capital	**180**	148	**538**	488
Adjustments:				
Decrease in finance lease receivable	**14**	13	**44**	42
Restructuring costs	**-**	1	**-**	1
Other	**2**	1	**3**	4
FFO	**196**	163	**585**	535
Deduct:				
Sustaining capital	**(40)**	(62)	**(173)**	(187)
Productivity capital	**(6)**	(2)	**(15)**	(6)
Insurance recoveries of sustaining capital expenditures	**-**	1	**-**	1
Dividends paid on preferred shares	**(10)**	(10)	**(30)**	(32)
Distributions paid to subsidiaries' non-controlling interests	**(38)**	(35)	**(136)**	(111)
Other	**(3)**	-	**(7)**	-
FCF	**99**	55	**224**	200
Weighted average number of common shares outstanding in the period	**288**	288	**288**	288
FFO per share	**0.68**	0.57	**2.03**	1.86
FCF per share	**0.34**	0.19	**0.78**	0.69

Comparable EBITDA

EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. 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 and Australia are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We depreciate these assets over their expected lives. ii) We also reclassify the deprecation 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 IESO relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator Contract (the "NUG Contract") effective Jan. 1, 2017. Under the new NUG Contract, we receive fixed monthly payments until December 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 record the payments we receive as revenues as a proxy for operating income, and continue to depreciate the facility until Dec. 31, 2018. iv) On commissioning of South Hedland, we prepaid certain electricity transmission and distribution costs. Interest is earned on the prepaid funds. We reclassify this interest as reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

A reconciliation of reported operating income to EBITDA and comparable EBITDA results for the three and nine months ended Sept. 30, 2017 and 2016, is set out below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	2017	2016
Operating income	20	47	106	195
Depreciation and amortization	158	145	455	414
EBITDA	178	192	561	609
Comparable reclassifications				
Finance lease income	15	16	47	49
Decrease in finance lease receivables	14	13	44	42
Mine depreciation	19	16	55	46
Australian interest income	1	-	1	-
Adjustments to earnings to arrive at comparable results:				
Impacts to revenue associated with certain de-designated and economic hedges	-	6	2	24
Impacts associated with Mississauga recontracting[1]	18	-	57	-
Asset impairment charge	-	-	20	-
Restructuring expense	-	1	-	1
Comparable EBITDA	245	244	787	771

(1) *Impacts associated with Mississauga recontracting for the nine months ended Sept. 30, 2017 are as follows: Revenue ($72 million), fuel and purchased power de-designated hedges ($12 million), and operations, maintenance, and administration ($3 million).*

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. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items.

Reconciliation of Non-IFRS Measures

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Comparable EBITDA	**245**	244	**787**	771
Provisions	**3**	1	**6**	(6)
Interest expense	**(58)**	(57)	**(171)**	(172)
Unrealized (gains) losses from risk management activities	**(5)**	(7)	**(19)**	(6)
Current income tax recovery	**(5)**	(6)	**(17)**	(17)
Decommissioning and restoration costs settled	**(5)**	(7)	**(12)**	(15)
Realized foreign exchange gain (loss)	**7**	3	**13**	2
Capital insurance recoveries	**-**	(1)	**-**	(1)
Other	**14**	(7)	**(2)**	(21)
FFO	**196**	163	**585**	535
Deduct:				
Sustaining capital	**(40)**	(62)	**(173)**	(187)
Productivity capital	**(6)**	(2)	**(15)**	(6)
Insurance recoveries of sustaining capital expenditures	**-**	1	**-**	1
Dividends paid on preferred shares	**(10)**	(10)	**(30)**	(32)
Distributions paid to subsidiaries' non-controlling interests	**(38)**	(35)	**(136)**	(111)
Other	**(3)**	-	**(7)**	-
FCF	**99**	55	**224**	200
Weighted average number of common shares outstanding in the period	**288**	288	**288**	288
FFO per share	**0.68**	0.57	**2.03**	1.86
FCF per share	**0.34**	0.19	**0.78**	0.69

FCF was up $44 million and $23 million during third quarter and year-to-date, respectively, compared to the same periods in 2016, mostly due to higher comparable EBITDA and the timing of sustaining and productivity capital expenditures, partially offset by higher distributions to our subsidiaries' non-controlling interests as a result of the settlement of the indexation dispute with the OEFC and higher unrealized mark-to-market gains.

Segmented Comparable Results

Each business segment assumes responsibility for its operating results measured to comparable EBITDA. Operating income and gross margin are also useful measures as they provide management and investors with a measurement of operating performance that is readily comparable from period to period.

Canadian Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Availability (%)	**78.6**	85.1	**82.2**	85.8
Contract production (GWh)	**4,665**	5,160	**14,065**	14,414
Merchant production (GWh)	**918**	1,000	**2,841**	2,895
Total production (GWh)	**5,583**	6,160	**16,906**	17,309
Gross installed capacity (MW)	**3,791**	3,791	**3,791**	3,791
Revenues	**252**	253	**750**	716
Fuel and purchased power	**135**	105	**379**	278
Comparable gross margin	**117**	148	**371**	438
Operations, maintenance, and administration	**42**	45	**133**	133
Taxes, other than income taxes	**3**	4	**10**	10
Net other operating income	**(10)**	-	**(30)**	-
Comparable EBITDA	**82**	99	**258**	295
Depreciation and amortization	**98**	75	**281**	230
Comparable operating income (loss)	**(16)**	24	**(23)**	65
Sustaining capital:				
Routine capital	**5**	5	**15**	18
Mine capital	**3**	8	**9**	15
Finance leases	**4**	4	**10**	10
Planned major maintenance	**8**	21	**43**	71
Total sustaining capital expenditures	**20**	38	**77**	114
Productivity capital	**2**	1	**7**	2
Total sustaining and productivity capital expenditures	**22**	39	**84**	116

Availability in the third quarter of 2017 was impacted by derates due to coal supply disruptions at our mine.

Production for the three months ended Sept. 30, 2017 decreased 577 GWh compared to the same period in 2016, due mainly to lower availability. Production for the nine months ended Sept. 30, 2017 decreased 403 GWh compared to the same period in 2016, as lower availability caused by higher planned and unplanned outages and derates due to lower coal supply during the third quarter offset lower paid curtailments on contracted assets and lower levels of economic dispatching on our non-contracted generation as a result of higher prices.

Comparable EBITDA for the three and nine months ended Sept. 30, 2017 decreased $17 million and $37 million, respectively, compared to the same periods in 2016. Although production was down, revenues were positively impacted by the pass through of higher environmental compliance costs to the PPA buyer ($17 million and $69 million, respectively). Most of the higher environmental compliance costs are passed through to the PPA buyer. Year-over-year, lower prices attributable to long-term financial contracts to economically hedge our future generation more than offset the increase in revenues from higher realized prices on our non-contracted volumes.

As expected, fuel and purchased power was impacted by higher coal costs related to the expected higher strip ratio, lower production from our mine, and higher environmental compliance costs in 2017. In addition, we incurred additional costs in the third quarter to mitigate the impact of lower productivity at our mine. These costs are expected to increase our fuel cost by an additional $2 per MWh for the remainder of 2017. For the three and nine months ended Sept. 30, 2017, comparable EBITDA also included $10 million and $30 million, respectively, related to OCA payment accruals included in net other operating income. We received our OCA payment in the third quarter.

Depreciation and amortization for the three and nine months ended Sept. 30, 2017 increased $23 million and $51 million, respectively, compared to the same periods in 2016, mainly due to shortening of the useful lives of the Keephills 3, Genesee 3, and Sundance 1 facilities and certain mine equipment at the Highvale mine. See the Accounting Changes section of this MD&A for further details.

Sustaining and productivity capital expenditures for the three and nine months ended Sept. 30, 2017 were lower by $17 million and $32 million, respectively, compared to the same periods in 2016, due to the timing of major outages in 2017 and pit stops executed in 2016 on our Sundance 1 and 2 units.

US Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Availability (%)	**95.7**	91.5	**56.6**	86.8
Adjusted availability (%)[1]	**95.7**	91.5	**83.2**	87.9
Contract sales volume (GWh)	**894**	925	**2,714**	2,756
Merchant sales volume (GWh)	**2,013**	2,385	**2,973**	2,972
Purchased power (GWh)	**(672)**	(1,093)	**(2,639)**	(2,961)
Total production (GWh)	**2,235**	2,217	**3,048**	2,767
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**147**	149	**296**	264
Fuel and purchased power	**109**	121	**188**	196
Comparable gross margin	**38**	28	**108**	68
Operations, maintenance, and administration	**13**	14	**37**	38
Taxes, other than income taxes	**1**	1	**3**	3
Comparable EBITDA	**24**	13	**68**	27
Depreciation and amortization	**19**	25	**50**	49
Comparable operating income (loss)	**5**	(12)	**18**	(22)
Sustaining capital:				
Routine capital	**-**	-	**2**	2
Finance leases	**1**	-	**3**	2
Planned major maintenance	**1**	-	**28**	11
Total sustaining capital expenditures	**2**	-	**33**	15
Productivity capital	**-**	-	**3**	-
Total sustaining and productivity capital expenditures	**2**	-	**36**	15

Availability for the three months ended Sept. 30, 2017 was up compared to 2016, due to higher unplanned outages in 2016. Year-to-date, availability was down compared to last year due to a forced outage on Unit 1 in January. Both Units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. We performed major maintenance on both units during that time. The lower availability had a nominal impact on our results as our contractual obligations were supplied with less expensive power purchased in the market during the first half of the year.

Production during the third quarter of 2017 was at the same level compared to 2016 as higher availability was partially offset by higher economic dispatching. Year-to-date, production increased 281 GWh compared to the same period in 2016, due mainly to lower economic dispatching in 2017, partially offset by higher unplanned and planned maintenance.

(1) Adjusted for economic dispatching.

Comparable EBITDA improved $11 million and $41 million, respectively, during the three and nine months ended Sept. 30, 2017, compared to the same periods in 2016, due mainly to higher prices on merchant and contracted revenues and lower transportation costs on coal. During the three and nine months ended Sept. 30, 2017, mark-to-market on certain forward financial contracts that do not qualify for hedge accounting resulted in a $1 million gain (2016 - $7 million gain) and a $6 million gain (2016 - $4 million loss).

Depreciation and amortization for the third quarter of 2017 was lower by $6 million compared to 2016, due to an increase to the decommissioning obligation balance for the Centralia Mine in 2016. Changes in period end discount rates impact the decommissioning obligation balance. As the mine is in the reclamation stage, adjustments to the decommissioning obligation are recognized in depreciation expense. On a year-to-date basis, depreciation and amortization were flat.

Sustaining capital expenditures in the third quarter were low at $2 million. Sustaining and productivity capital expenditures for the nine months ended Sept. 30, 2017 increased $21 million compared to 2016 and totalled $36 million due to planned outages executed during the second quarter of 2017. Productivity capital was invested in the installation of inspection equipment to optimize heat rates on coal and improve air distribution systems. See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

Canadian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Availability (%)	**87.3**	89.9	**90.2**	95.0
Contract production (GWh)	**357**	700	**1,128**	2,154
Merchant production (GWh)	**98**	187	**148**	253
Total production (GWh)	**455**	887	**1,276**	2,407
Gross installed capacity (MW)(1)	**953**	1,057	**953**	1,057
Revenues	**94**	115	**331**	342
Fuel and purchased power	**28**	49	**90**	126
Comparable gross margin	**66**	66	**241**	216
Operations, maintenance, and administration	**10**	13	**39**	41
Taxes, other than income taxes	**-**	-	**1**	1
Comparable EBITDA	**56**	53	**201**	174
Depreciation and amortization	**30**	25	**88**	80
Comparable operating income	**26**	28	**113**	94
Sustaining capital:				
Routine capital	**-**	1	**4**	3
Planned major maintenance	**3**	1	**22**	3
Total sustaining capital	**3**	2	**26**	6

Availability for the three months ended Sept. 30, 2017 decreased approximately 3 per cent compared to the same period in 2016, primarily due to planned and unplanned maintenance work at our Sarnia plant. Availability for the nine months ended Sept. 30, 2017 decreased approximately 5 per cent compared to the same period in 2016, primarily due to a planned major inspection at Sarnia, the base to cycling conversion project at Windsor, and an unplanned steam turbine outage at Windsor.

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease, the portion of the Poplar Creek facility we continue to own and excludes the Mississauga cogeneration facility, which has been shutdown temporarily due to the recontracting in the fourth quarter of 2016.

Production for the three and nine months ended Sept. 30, 2017 decreased 432 GWh and 1,131 GWh compared to the same periods in 2016, primarily due to softer markets in Ontario in 2017 and changes in contracts at Mississauga and Windsor at the end of 2016. The Mississauga gas facility has been temporarily shut down effective Jan. 1, 2017, as we have no delivery obligations under the new agreement. We will continue to receive monthly capacity payments until the end of 2018 under the Mississauga contract.

Comparable EBITDA for the three months ended Sept. 30, 2017 increased $3 million compared to the same period in 2016, due primarily to the positive impact of the temporary shut-down of our Mississauga gas facility. Comparable EBITDA for the nine months ended Sept. 30, 2017 increased $27 million compared to 2016, primarily due to the settlement with the OEFC of the retroactive adjustment to price indices at Ottawa and Windsor and the positive impact of the temporary shut-down at our Mississauga gas facility, partially offset by unfavourable changes in unrealized mark-to-market positions on gas contracts that do not qualify for hedge accounting and the reduction in contracted revenues from our Windsor facility. The Mississauga, Ottawa, Windsor, and Fort Saskatchewan facilities are owned through our 50.01 per cent interest in TA Cogeneration L.P. ("TA Cogen").

Depreciation for the three and nine months ended Sept. 30, 2017 increased $5 million and $8 million compared to the same periods in 2016. We record the decrease in the finance lease receivable as a comparable increase in depreciation, as this amount, and the finance lease income, is included in comparable revenues as a proxy for capacity revenues for this segment.

Sustaining capital for the nine months ended Sept. 30, 2017 increased $20 million compared to the same period in 2016, primarily due to the scheduled maintenance at Sarnia and the base to cycling conversion project at Windsor to increase its flexibility to respond to market prices.

Australian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Availability (%)	**96.2**	96.6	**93.6**	93.7
Contract production (GWh)	**476**	389	**1,346**	1,132
Gross installed capacity (MW)[1]	**575**	425	**575**	425
Revenues	**56**	43	**138**	130
Fuel and purchased power	**2**	5	**8**	16
Comparable gross margin	**54**	38	**130**	114
Operations, maintenance, and administration	**9**	6	**22**	18
Comparable EBITDA	**45**	32	**108**	96
Depreciation and amortization	**10**	5	**26**	13
Comparable operating income	**35**	27	**82**	83
Sustaining capital:				
Routine capital	**5**	-	**7**	1
Planned major maintenance	**-**	6	**1**	11
Total sustaining capital	**5**	6	**8**	12

Production for the three and nine months ended Sept. 30, 2017 increased 87 GWh and 214 GWh, respectively, compared to the same periods in 2016, due to the commissioning of our South Hedland power project on July 28, 2017 and an increase in customer load. Due to the nature of our contracts, the increase in customer load did not have a significant financial impact on our results as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA was up for the three and nine months ended Sept. 30, 2017, compared to the same periods in 2016, due to the commissioning of our South Hedland power project in July 2017.

(1) Includes production capacity for the Solomon power station, which has been accounted for as a finance lease.

Depreciation and amortization for the three and nine months ended Sept. 30, 2017 increased $5 million and $13 million, respectively, compared to the same periods in 2016, due to the full commissioning of our South Hedland power project in July 2017. See the Significant and Subsequent Events section of this MD&A for further details.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Availability (%)	**94.6**	94.1	**95.9**	95.3
Contract production (GWh)	**334**	425	**1,598**	1,622
Merchant production (GWh)	**163**	206	**730**	871
Total production (GWh)	**497**	631	**2,328**	2,493
Gross installed capacity (MW)	**1,363**	1,408	**1,363**	1,408
Revenues	**42**	49	**188**	188
Fuel and purchased power	**2**	3	**10**	15
Comparable gross margin	**40**	46	**178**	173
Operations, maintenance, and administration	**12**	13	**36**	39
Taxes, other than income taxes	**2**	2	**6**	6
Net other operating income	**-**	(1)	**-**	(1)
Comparable EBITDA	**26**	32	**136**	129
Depreciation and amortization	**27**	29	**82**	88
Comparable operating income	**(1)**	3	**54**	41
Sustaining capital:				
Routine capital	**1**	1	**1**	2
Planned major maintenance	**3**	2	**8**	8
Total sustaining capital expenditures	**4**	3	**9**	10
Insurance recoveries of sustaining capital expenditures	**-**	(1)	**-**	(1)
Productivity capital	**1**	-	**1**	3
Net amount	**5**	2	**10**	12

Production for the three months ended Sept. 30, 2017 decreased 134 GWh compared to the same period in 2016, primarily due to lower wind resources and the sale of the Wintering Hills Wind facility in the first quarter of 2017. On a year-to-date basis, production was down 165 GWh, as the stronger wind resource in the second quarter did not fully offset the impact of the lower wind resource this quarter and the sale of the Wintering Hills Wind facility in the first quarter of 2017.

Comparable EBITDA for the three months ended Sept. 30, 2017 decreased $6 million compared to the same period in 2016, primarily driven by lower volumes at contracted facilities. Comparable EBITDA for the nine months ended Sept. 30, 2017 increased $7 million compared to 2016 due to increased renewable energy certificate sales in 2017 and lower operations, maintenance, and administration expenses after renegotiating Long Term Service Agreements with service providers, partially offset by lower volumes.

Depreciation for the three and nine months ended Sept. 30, 2017 decreased $2 million and $6 million, respectively, compared to the same periods in 2016, primarily due to the disposition of the Wintering Hills merchant wind facility which closed on March 1, 2017, the retirement of Cowley Ridge in 2016, and declining balance depreciation at our Solar facilities.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	2017	2016
Contract production (GWh)	482	450	1,544	1,349
Merchant production (GWh)	39	35	78	76
Total production (GWh)	521	485	1,622	1,425
Gross installed capacity (MW)	926	926	926	926
Revenues	31	30	95	96
Fuel and purchased power	2	2	5	6
Comparable gross margin	29	28	90	90
Operations, maintenance, and administration	10	8	27	25
Taxes, other than income taxes	-	1	2	3
Comparable EBITDA	19	19	61	62
Depreciation and amortization	7	7	24	20
Comparable operating income	12	12	37	42
Sustaining capital:				
Routine capital, excluding hydro life extension	3	2	6	4
Hydro life extension	-	3	-	9
Planned major maintenance	1	3	3	5
Total	4	8	9	18
Productivity capital	1	-	1	-
Total sustaining and productivity capital expenditures	5	8	10	18

Production for the three months ended Sept. 30, 2017 increased 36 GWh compared to the same period in 2016, due to continued strong water resources in Alberta and Ontario. Production for the nine months ended Sept. 30, 2017 increased 197 GWh compared to the same period in 2016, primarily due to higher water resources from spring run-off in Alberta.

Comparable EBITDA for the three and nine months ended Sept. 30, 2017 was flat compared to the same periods in 2016, as higher volumes were offset by increased operations, maintenance, and administration costs due mostly to contractor spend on Project Greenlight improvement initiatives. See the Strategic Growth and Corporate Transformation section of this MD&A for further details. Last year, we recorded a $3 million positive adjustment in the first quarter relating to a prior year metering issue at one of our facilities.

Depreciation for the nine months ended Sept. 30, 2017 increased $4 million compared to the same period in 2016, primarily due a higher asset base.

Sustaining capital for the three and nine months ended Sept. 30, 2017 decreased $4 million and $9 million, respectively, compared to the same periods in 2016, primarily due to the life extension projects at Bighorn and Brazeau in 2016.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Revenues and comparable gross margin	**17**	16	**36**	59
Operations, maintenance, and administration	**5**	6	**16**	20
Comparable EBITDA	**12**	10	**20**	39
Depreciation and amortization	**-**	1	**1**	2
Comparable operating income	**12**	9	**19**	37

For the three months ended Sept. 30, 2017, comparable EBITDA was up $2 million compared to 2016, due to a return to normal level of gross margin. On a year to date basis, results were lower compared to 2016, due to unfavourable first quarter of 2017 results impacted by warm winter weather in the Northeast, significant precipitation in the Pacific Northwest, and reduced margins from our customer business.

Corporate

Our Corporate overhead costs were $5 million and $14 million higher, respectively, for the three and nine months ended Sept. 30, 2017, compared to 2016. Corporate costs in 2017 include certain costs relating to our corporate transformation that we expect will translate into significant long-term cost savings. See the Strategic Growth and Corporate Transformation section of this MD&A for further details. The first quarter of 2017 also includes the reclassification of incentives for 2016 between our operational segments and our Corporate segment.

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 by 2018.

FFO before Interest to Adjusted Interest Coverage

As at	Sept. 30, 2017[1]	Dec. 31, 2016
FFO	**813**	763
Add: Interest on debt net of interest income and capitalized interest	**217**	223
FFO before interest	**1,030**	986
Interest on debt net of interest income	**232**	239
Add: 50 per cent of dividends paid on preferred shares	**20**	21
Adjusted interest	**252**	260
FFO before interest to adjusted interest coverage (times)	**4.1**	3.8

Our target for FFO before interest to adjusted interest coverage is four to five times. The ratio improved slightly compared to 2016 due to stronger FFO and lower interest on debt, as we continue to execute on our deleveraging plan.

(1) Last 12 months. Our target range for FFO in 2017 is $765 million to $820 million.

Adjusted FFO to Adjusted Net Debt

As at	Sept. 30, 2017	Dec. 31, 2016
FFO[1,2]	813	763
Less: 50 per cent of dividends paid on preferred shares[1]	(20)	(21)
Adjusted FFO[1]	793	742
Period-end long-term debt[3]	3,780	4,361
Less: Cash and cash equivalents	(87)	(305)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of economic hedging instruments on debt[4]	(26)	(163)
Adjusted net debt	4,138	4,364
Adjusted FFO to adjusted net debt (%)	19.2	17.0

Our adjusted FFO to adjusted net debt ratio improved to 19.2 per cent, due to the reduction in our net debt year-to-date and the improvement in FFO. We expect this metric to improve towards our targeted level of 20 to 25 per cent as a result of expected increased comparable EBITDA from our operations at South Hedland, fully commissioned in July 2017.

Adjusted Net Debt to Comparable EBITDA

As at	Sept. 30, 2017	Dec. 31, 2016
Period-end long-term debt[3]	3,780	4,361
Less: Cash and cash equivalents	(87)	(305)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of economic hedging instruments on debt[4]	(26)	(163)
Adjusted net debt	4,138	4,364
Comparable EBITDA[1]	1,161	1,145
Adjusted net debt to comparable EBITDA (times)	3.6	3.8

As at Sept. 30, 2017 our adjusted net debt to comparable EBITDA ratio improved compared to 2016, mainly due to the significant reduction in our net debt during the year. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. We expect this metric to trend towards our targeted level due to the expected increase in comparable EBITDA from operations at South Hedland, fully commissioned in July 2017.

(1) Last 12 months.
(2) Our target range for FFO in 2017 is $765 million to $820 million.
(3) Includes finance lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at Sept. 30, 2017 and Dec. 31, 2016. During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Strategic Growth and Corporate Transformation

Kent Hills Wind Project

During the second quarter of 2017, TransAlta Renewables entered into a long-term contract with the New Brunswick Power Corporation for the sale of all power generated by an additional 17.25 MW of capacity to be installed at our Kent Hills wind project.

This is an expansion project of our existing Kent Hills wind project on approximately five to ten acres of Crown land, increasing the total operating capacity of the Kent Hills wind project to approximately 167 MW. As part of the regulatory process, we submitted an Environmental Impact Assessment to the province of New Brunswick in late September. Provided environmental approvals are received, we expect to begin the construction phase in the spring of 2018.

Brazeau Hydro Pumped Storage

The Brazeau Hydro Pumped Storage project is an innovative way to generate and shape clean electricity. It will store water that can be used to both generate power when it is needed and store excess power supply when demand is low. When there is excess renewable generation in periods of low demand, water will be pumped from the lower reservoir and stored in the upper reservoir to be used later. When demand is high and generation from other renewables generation is not sufficient, water will flow back through a turbine using gravity to generate clean electricity. The Brazeau Pumped storage project is a focus for us, as it has existing infrastructure that reduces the cost and environmental footprint of the project, is situated close to existing transmission infrastructure, and allows for increased renewable development by balancing intermittent generation from wind and solar.

We are currently working to secure a path that will advance our investment in the project and secure a long-term contract for the project. The Brazeau Hydro Pumped Storage project is expected to have new capacity ranging between 600 MW to 900 MW, bringing the total Brazeau facility to 955 – 1,255 MW, post-completion. We estimate an investment in the range of $1.8 billion to $2.5 billion and expect construction to begin upon receipt of a long-term contract and regulatory approvals, between 2020 and 2021, with operations to commence in 2025. This year we are investing $5 million to $10 million to advance the environmental study, work with stakeholders, and execute geotechnical work to help further our design and construction phase.

Other Growth Projects

We are also advancing our plans to build, own, and operate the following growth projects:

- The Antelope Coulee Wind project - a wind project located in southwest Saskatchewan, comprised of up to 52 turbines, with a total capacity of between 100 to 200 MW, depending on the approved size of the project. If successful, construction could begin in 2019 with a proposed commercial operation date of no later than April 2021. If built, the project is expected to produce 700,000 MWh of electricity annually, enough to power around 70,000 homes.
- The Garden Plain Wind project – a wind project located near Drumheller, Alberta, comprised of 36 turbines, with a total capacity of approximately 130 MW. The proposed project would be developed in two phases. We are in the late stages of finalizing the project design and are preparing to submit an application to the AUC for construction and permitting approval, which is expected in March 2018. If built, the project is expected to produce 455,000 MWh of electricity annually, enough to power around 50,000 homes.
- The Tono Solar Project – a solar project, using Tier 1 solar technologies with proven capabilities, located on reclaimed mine land at our existing Centralia mine site, adjacent to our Centralia coal facility. We are considering various capacity scenarios between 40 to 180 MW and intend to submit a bid into Puget Sound Energy's request for proposal for renewable power for a 25-year agreement.

Project Greenlight

Our transformation project is a top priority for us. Driven by engagement from all employees, the intent is to deliver ambitious improvements in every part of our company. Initiatives include increasing revenue, improving generation, reducing operating and maintenance costs, reducing overhead costs and financing costs, and optimizing our capital spend. We expect Project Greenlight to deliver sustainable pre-tax savings of approximately $50 million to $70 million annually, commencing in 2018. We are on track to achieve our expected annual savings targets. Our internal cost to execute these initiatives is expected to be between $25 million to $35 million in 2017. We also expect to spend $20 million to $25 million related to productivity capital in 2017.

Significant and Subsequent Events

Balancing Pool PPA Termination

On Sept. 18, 2017, we received formal notice from the Balancing Pool for the termination of the Sundance PPAs effective March 31, 2018. The termination of the Sundance PPAs by the Balancing Pool was not a surprise and is expected to positively impact our business.

The expected impacts of the termination include:

- Approximately $215 million in compensation for the net book value of the assets as compared to the Balancing Pool's estimate of approximately $157 million. The Balancing Pool's estimate differs because it excludes certain mining assets which the Corporation believes should be included in the net book value calculation. The termination proceeds will be used to repay debt maturing in 2018.
- Increased operational flexibility, including with respect to dispatching of generation from the affected units, maintenance and turnaround schedules, and the timing of the coal-to-gas conversions.

After the termination of the Sundance PPAs, we will have approximately 2,000MW of capacity under Alberta PPAs, representing approximately 12 per cent of the generation capacity in Alberta. The Corporation believes that the cash flow generated by its portfolio of coal, gas and renewable assets in Alberta will be maintained following the termination of the Sundance PPAs. The Sundance A PPA expires at the end of 2017 and, as such, it was not included in the Balancing Pool's PPA termination considerations.

TransAlta Renewables $260 Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Sept. 27, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, Kent Hills Wind LP ("KHWLP"), priced an approximate $260 million bond offering, by way of a private placement, secured by, among other things, a first ranking charge over all assets of KHWLP. The offering closed on Oct. 2, 2017. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly and maturing Nov. 30, 2033. The net proceeds will be used to fund the construction costs for the 17.25 MW Kent Hills expansion (upon meeting certain completion tests and other specified conditions) and were also used to make advances to Canadian Hydro Developers Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP.

At the same time, CHD, our subsidiary, provided notice that they would be early redeeming all their unsecured debentures with a weighted average interest rate of 6.3 per cent. The debentures were scheduled to mature in June of 2018. On Oct. 12, 2017, they redeemed the unsecured debentures for $201 million in total, comprised of principal of $191 million, an early redemption premium of $6 million, and accrued interest of $4 million. A $6 million loss was recognized in net interest expense for the three and nine months ended Sept. 30, 2017.

Commissioning of South Hedland Facility and Conversion of Class B Shares

During the quarter, the final stages of construction of our South Hedland power station, including reliability runs, were completed. The facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, we converted our 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, our common share equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables. TransAlta Renewables also announced an increase in their monthly dividend rate of approximately 7 per cent.

On Aug. 1, 2017, FMG issued a news release indicating that it had notified us that, in its view, the South Hedland power station has not yet satisfied the requisite performance criteria under the South Hedland power purchase agreement between FMG and TransAlta. Our view is that all the conditions to establish that commercial operations have been achieved under the terms of the power purchase agreement with FMG have been satisfied in full. Horizon Power has not disputed commercial operation.

Termination of Solomon Power Purchase Arrangement

On Aug. 1, 2017, we received notice that FMG intends to repurchase the Solomon Power facility for approximately US$335 million. FMG is expected to complete its acquisition of the Solomon Power Station in November 2017. Our subsidiary, TransAlta Renewables will utilize the proceeds in part to repay the credit facility used to fund the remaining development of the South Hedland power station and for general corporate purposes.

Settlement of Dispute for the Ottawa and Windsor Facilities

During the first half of the year we settled the contract indexation dispute with the OEFC relating to our Ottawa and Windsor generating facilities for proceeds totalling $34 million.

Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, we announced that the minimum election notices received did not meet the requirements required to give effect to the conversion of Series E Preferred Shares into the Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and their dividend rate will remain fixed for the subsequent five-year period.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements required to give effect to the conversion of the Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and their dividend rate will remain fixed for the subsequent five-year period.

TransAlta Renewables Credit Facility

On July 24, 2017, TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The agreement is fully committed for four years, expiring in 2021. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with this new credit agreement, the $350 million credit facility provided by TransAlta to TransAlta Renewables was cancelled. At the same time, we extended our syndicated credit facility to 2021 and reduced the size of the facility by $500 million to $1 billion. Consolidated syndicated credit facilities remain at $1.5 billion.

Appointment of Director

On July 13, 2017, the Board of Directors (the "Board") appointed the Honourable Rona Ambrose to the Board effective July 13, 2017. Ms. Ambrose was the former Leader of Canada's Official Opposition in the House of Commons and former leader of the Conservative Party of Canada. She also acted as Minister of the Crown across nine government departments, including serving as Vice Chair of the Treasury Board and Chair of the cabinet committee for public safety, justice and aboriginal issues.

Transition to Clean Power in Alberta and Impairment Charge

On April 19, 2017, we announced our strategy to accelerate our transition to gas and renewables generation. The strategy includes the following steps:

- retirement of Sundance Unit 1 effective Jan. 1, 2018;
- mothballing of Sundance Unit 2 effective Jan. 1, 2018, for a period of 2 years; and
- conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2023 timeframe, thereby extending the useful lives of these units until the mid-2030's.

The retirement of Sundance Unit 1 and mothballing of Sundance Unit 2 reflects the limited economic viability of the units upon the expiry of their PPA due to the current oversupplied Alberta power market and low power price environment and is not expected to materially impact our forecasted cash flows for 2018 and 2019.

The benefits of converting coal-fired units to gas-fired generation include:

- significantly lowering carbon intensities, emissions, and carbon costs;
- significantly lowering operating and sustaining capital costs;
- increasing operating flexibility; and
- adding between five-to-ten years of economic life to each converted unit.

Sundance Units 1 and 2

Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide us with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively comprise 560 MW of the 2,141 MW at the Sundance power plants, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expires on Dec. 31, 2017.

In the second quarter of 2017, we recognized an impairment loss on Sundance Unit 1 in the amount of $20 million due to our decision to early retire Sundance Unit 1. Previously, we had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintains our flexibility to operate the Unit as part of our Alberta Merchant cash-generating unit to 2021.

Coal-to-Gas Conversions

In December 2016, notice was given by Environment and Climate Change Canada of its intention to amend regulations to phase out coal-fired generation by 2030 while permitting the conversion of boiler units from coal to natural gas fired generation for a period of up to 15 years or until 2045, whichever comes first. These regulations, which will facilitate our proposed coal-to-gas conversions, remain a work-in-progress. We are engaged with the Government of Canada in the development of required regulatory regime.

We are planning the conversion of Sundance Units 3 and 6 and Keephills Units 1 and 2 to gas-fired generation in the 2021 to 2023 timeframe, thereby extending the useful lives of these units until the mid-2030's. We expect that the capacity of Sundance Units 3 to 6 and Keephills 1 and 2 will not change following conversion, which will result in a reduction of approximately 40 per cent of carbon emissions from these units while maintaining approximately 2,400 MWs in the Alberta power grid.

Our total capital commitment for the coal-to-gas conversions is expected to be approximately $300 million, mostly invested between 2021 to 2023. We anticipate funding the conversions with free cash flow at that time. These units are expected to provide low cost capacity and to be competitive in the upcoming capacity market auctions. We expect the first auction to occur in 2019 for 2021 and that federal and provincial regulations will be adopted to facilitate coal-to-gas conversions. We continue to be engaged with government in the development of the required regulatory regime. This year, we are committing $3 million to $5 million to advance engineering for the conversion.

Alberta Off-Coal Agreement

On Nov. 24, 2016, we announced that we entered into the OCA with the Government of Alberta on transition payments in exchange for the cessation of coal-fired emissions from the Keephills 3, Genesee 3, and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, we receive annual cash payments on or before July 31 of approximately $39.7 million ($37.2 million, net to the Corporation), commencing Jan. 1, 2017 and terminating at the end of 2030. We recognize the OCA payments evenly throughout the year. Accordingly, during the three and nine months ended Sept. 30, 2017, approximately $10 million and $30 million, respectively, were recognized in Net Other Operating Income in the Condensed Consolidated Statement of Earnings. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. We received our first payment under the OCA in the third quarter of 2017.

Mississauga Cogeneration Facility New Contract

On Dec. 22, 2016, we announced that we had signed a NUG Contract with the Independent Electricity System Operator for our Mississauga cogeneration facility. The NUG Contract became effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, we agreed to terminate effective Dec. 31, 2016, the Mississauga cogeneration facility's pre-existing contract with the Ontario Electricity Financial Corporation ("OEFC"), which would have otherwise terminated in December 2018. The NUG Contract provides us stable monthly payments totalling approximately $209 million until Dec. 31, 2018.

Refer to our 2016 Annual MD&A for further information regarding the Mississauga NUG Contract.

Wintering Hills Sale

On March 1, 2017, we closed the previously announced sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. Proceeds from the sale have been used for general corporate purposes, including reducing our debt and funding future renewables growth.

Credit Ratings Change

We maintain investment grade ratings from three credit rating agencies. Earlier this year, Fitch Ratings reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable, DBRS Limited changed our Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating BBB to BBB (low) (changed to stable from negative), and Standard and Poor's reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- but changed the outlook from stable to negative.

Regulatory Updates

Refer to the Regional Regulation and Compliance discussion in our 2016 Annual MD&A for further details that supplement the recent developments as discussed below.

Alberta

In March 2016, Alberta began development of its renewable energy procurement process design for the Alberta Electric System Operator ("AESO") to procure a first block of renewable generation projects to be in-service by 2019. On Sept. 14, 2016, the Government of Alberta re-confirmed its commitment to achieve 30 per cent renewables in Alberta's electricity energy mix by 2030.

In January 2017, the AESO commenced consultation sessions and initiated the process for the development of a capacity market for the Province of Alberta. In May 2017, the AESO published a Straw Alberta market proposal for discussion.

The AESO has now assembled five working groups to develop and provide recommendations on the design of Alberta's capacity market. The groups are comprised of industry stakeholders that are working collaboratively across five design streams for the market. The working groups are tasked with developing their conclusions and recommendations into papers that will be publicly issued for stakeholder comment. The comments received from the stakeholder process will be considered by the working groups to refine the recommendations. The first paper was issued on Aug. 30, 2017 and comments were posted on Sept. 20, 2017. The working groups reconvened starting on Sept. 12, 2017 with the intent to issue another paper in December 2017 and March 2018. A final recommendation paper will be issued in June 2018. The AESO will begin formalizing the capacity market design and implementing it in the second half of 2018 with first procurement expected in second half of 2019, to be effective in 2021 with first capacity contracts awarded at that time.

Ontario

On Feb. 25, 2016, Ontario released draft regulations for its GHG cap-and-trade program that were finalized on May 19, 2016. The regulations became effective Jan. 1, 2017, and apply to all fossil fuels used for electricity generation. The majority of our gas-fired generation in Ontario will not be significantly impacted by virtue of change-in-law provisions within existing PPAs.

Capital Structure and Liquidity

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

	Sept. 30, 2017		Dec. 31, 2016	
	$	%	$	%
TransAlta Corporation				
Recourse debt - CAD debentures	1,046	13	1,045	12
Recourse debt - U.S. senior notes	1,482	18	2,151	25
U.S. tax equity financing	32	-	39	-
Other	14	-	15	-
Less: cash and cash equivalents	(75)	(1)	(290)	(3)
Less: fair value asset of economic hedging instruments on debt[1]	(26)	-	(163)	(2)
Net recourse debt	2,473	30	2,797	32
Non-recourse debt	217	3	245	3
Finance lease obligations	65	1	73	1
Total net debt - TransAlta Corporation	2,755	34	3,115	36
TransAlta Renewables				
Credit facility	147	2	-	-
Less: cash and cash equivalents	(12)	-	(15)	-
Net recourse debt	135	2	(15)	-
Non-recourse debt	777	10	793	9
Total net debt - TransAlta Renewables	912	12	778	9
Total consolidated net debt	3,667	46	3,893	45
Non-controlling interests	1,083	13	1,152	14
Equity attributable to shareholders				
Common shares	3,094	38	3,094	36
Preferred shares	942	12	942	11
Contributed surplus, deficit, and accumulated other comprehensive income	(643)	(9)	(525)	(6)
Total capital	8,143	100	8,556	100

We continued down our path of strengthening our financial position during 2017 and reduced our total net debt by $226 million. In the second quarter, we made a scheduled US$400 million US Senior Note repayment. This repayment was hedged with a cross currency swap entered into on issuance of the debt that effectively reduced our Canadian dollar repayment by approximately $107 million. On Oct 2, 2017, we closed a $260 million bond offering secured by our Kent Hills Wind Farms, and on Oct. 12, 2017, we used $197 million of the proceeds to early redeem all of CHD's outstanding non-recourse debentures. These actions align with our strategy of issuing project level amortizing debt to proactively manage upcoming debt maturities.

On Jan. 18, 2017, we renewed a US base shelf prospectus that allows for the issuance of up to $2.0 billion aggregate principal amount (or its equivalent in other currencies) of common shares, first preferred shares, warrants, subscription receipts and debt securities from time to time. We also have a Canadian base shelf prospectus, which would allow for the issuance of common shares, first preferred shares, warrants, subscription receipts and debt securities from time to time. The specific terms of any offering of securities is to be determined at the date of issue.

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

The weakening of the US dollar has decreased our long-term debt balances by $133 million since Dec. 31, 2016. Almost all our U.S.-denominated debt is hedged[1] either through financial contracts or net investments in our U.S. operations. During the period, these changes in our U.S.-denominated debt were offset as follows:

As at	Sept. 30, 2017	Dec. 31, 2016
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	**(81)**	(35)
Foreign currency economic cash flow hedges on debt[1]	**(46)**	(29)
Economic hedges and other	**(6)**	(3)
Total	**(133)**	(67)

During the period through Dec. 31, 2020, we have approximately $1.9 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising debt secured by our contracted cash flows over the next 12 months. The timing of any such financings will be adjusted to match the redeployment of capital. The expected proceeds of US$335 million from FMG for the repurchase of the Solomon Power Facility and Sundance PPA termination proceeds of $215 million will provide us more financial flexibility in executing the plan. For further details see the Significant and Subsequent Events section of this MD&A. We also expect to continue our deleveraging strategy, as a significant part of our FCF over the next four years will be allocated to debt reduction.

Our credit facilities provide us with significant liquidity. On July 24, 2017, TransAlta Renewables entered into a $500 million syndicated credit agreement. At the same time, we agreed to reduce our facility by the same amount so that consolidated syndicated credit facilities remained constant at $1.5 billon. As a result, at Sept. 30, 2017, we maintained our total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities. We are in compliance with the terms of the credit facilities. In total, $1.3 billion (Dec. 31, 2016 - $1.4 billion) was available for use. At Sept. 30, 2017, the $0.7 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.1 billion (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). These facilities are comprised of a $1 billion committed syndicated bank facility expiring in 2021, a $500 million committed syndicated bank facility expiring in 2021 at TransAlta Renewables, one bilateral credit facility of US$200 million, expiring in 2020, and three bilateral credit facilities, totalling $240 million, expiring in 2019.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, and Mass Solar bonds 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 third quarter. However, funds in these entities that have accumulated since the third quarter test, will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2017. At Sept. 30, 2017, $26 million (Dec. 31, 2016 - $24 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 Sept. 30, 2017. However, as at Sept. 30, 2017, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letter of credits, and was not available for general use.

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

Share Capital

The following table outlines the common and preferred shares issued and outstanding:

As at	Oct. 31, 2017	Sept. 30, 2017	Dec. 31, 2016
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	287.9
Preferred shares			
Series A	10.2	10.2	10.2
Series B	1.8	1.8	1.8
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests

As of Sept. 30, 2017, our voting rights interest in TransAlta Renewables was 64.0 per cent (Dec. 31, 2016 – 64.0 per cent). The South Hedland facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's common share equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The stable and predictable cash flows generated by TransAlta Renewables' assets has attracted favourable equity valuations from investors, allowing TransAlta the potential to raise equity capital. We remain committed to maintaining our position as the majority shareholder and sponsor of TransAlta Renewables, with a stated goal of maintaining our interest between 60 to 80 per cent.

We also own 50.01 per cent of TA Cogen which owns, operates, or has an interest in four natural-gas-fired facilities and a 50 per cent interest in a coal-fired generating facility.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Interest on debt	**53**	59	**165**	170
Interest income	**(1)**	-	**(3)**	(1)
Capitalized interest	**(2)**	(4)	**(10)**	(11)
Loss on redemption of bonds	**6**	-	**6**	1
Interest on finance lease obligations	**1**	1	**3**	3
Other[1]	**6**	(4)	**13**	5
Accretion of provisions	**6**	4	**16**	15
Net interest expense	**69**	56	**190**	182

Net interest expense increased during the three and nine months ended Sept. 30, 2017 compared to 2016, due mostly to lower capitalized interest and the redemption premium recognized on early redemption of the CHD debentures, which together more than offset lower interest on debt and higher interest income. During 2016, interest accruals were included relating to our Keephills 1 outage arbitration.

(1) 2016 includes interest accrued related to the Keephills 1 outage arbitration.

Dividends to Shareholders

On Dec. 19, 2016, we declared quarterly dividends per common share and preferred shares payable to shareholders relating to the period covering the first quarter of 2017. A total of $12 million and $10 million in common and preferred share dividends were paid during the first quarter of 2017, respectively.

The following are the 2017 common and preferred shares dividends declared:

Declaration date	Common dividends per share	Preferred Series dividends per share A	B	C	E	G
April 19, 2017	0.04	0.16931	0.15645	0.2875	0.3125	0.33125
July 18, 2017	0.04	0.16931	0.16125	0.25169	0.3125	0.33125
Oct. 30, 2017	0.04	0.16931	0.17467	0.25169	0.32463	0.33125

Non-Controlling Interests

Reported earnings attributable to non-controlling interests for the three months ended Sept. 30, 2017 decreased by $37 million, compared to the same period in 2016, due mostly to lower net earnings at TransAlta Renewables. Year-to-date, reported earnings attributable to non-controlling interests was up $6 million compared to 2016. In both periods, net earnings were negatively impacted by the impairment of the investment in the Australian business recognized as a result of the termination of the Solomon PPA by FMG and by higher net interest expense due to higher outstanding borrowings. In the third quarter of 2017, TransAlta Renewables' net earnings were also negatively impacted by higher foreign exchange losses mainly due to the weakening of both the U.S. and Australian dollars against the Canadian dollar.

Other Consolidated Analysis

Financial Position

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2016 to Sept. 30, 2017:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	(218)	Repayment of long-term debt ($480 million), net of gain on cross currency swap, partially offset by proceeds from sale of our Wintering Hills merchant wind facility ($61 million) and free cash flow
Trade and other receivables	411	Timing of customer receipts and seasonality of revenue, and reclassification of the long-term Solomon finance lease receivables as current ($412 million)
Inventory	20	Transfer of inventory from PP&E ($15 million)
Assets held for sale	(61)	Closing of the sale of the Wintering Hills merchant wind facility
Finance lease receivables (long term)	(489)	Reclassification of Solomon finance lease to current ($412 million), unfavourable changes in foreign exchange rates ($35 million) and scheduled receipts ($44 million)
Property, plant, and equipment, net	(170)	Depreciation for the period ($465 million) and unfavourable changes in foreign exchange rates ($56 million), impairment charge ($20 million), partially offset by additions ($266 million), and revisions to decommissioning and restoration costs ($126 million)
Intangible assets	12	Additions ($22 million), partially offset by amortization ($8 million)
Risk management assets (current and long term)	(142)	Contract settlements and unfavourable changes in foreign exchange rates, partially offset by market price movements
Other	2	
Total decrease in assets	**(635)**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	98	Timing of payments and accruals
Dividends payable	(27)	Timing of the declaration of common dividends
Credit facilities, long term debt, and finance lease obligations (including current portion)	(581)	Repayments ($588 million) and favourable effects of changes in foreign exchange rates ($133 million), partially offset by increase in credit facility ($147 million)
Decommissioning and other provisions (current and long term)	124	Impact of lower discount rate due to shortened useful lives on certain Alberta coal assets
Deferred income tax liabilities	(45)	Decrease in taxable temporary differences
Risk management liabilities (current and long term)	(16)	Favourable market price changes, partially offset by unfavourable foreign exchange
Equity attributable to shareholders	(118)	Re-allocation of equity in TransAlta Renewables ($50 million), common share dividends ($24 million), preferred share dividends ($20 million), and net loss ($25 million)
Non-controlling interests	(69)	Distributions paid and payable ($130 million), intercompany available-for-sale-investments ($12 million), partially offset by re-allocation of equity in TransAlta Renewables ($50 million) and net earnings ($23 million)
Other	(1)	
Total decrease in liabilities and equity	**(635)**	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2017 compared to the same periods in 2016:

3 months ended Sept. 30	2017	2016	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	**50**	93	(43)	
Provided by (used in):				
Operating activities	**201**	228	(27)	Unfavourable change in non-cash working capital ($59 million), partially offset by an increase in cash earnings ($32 million)
Investing activities	**(145)**	(99)	(46)	Unfavourable change in investing working capital ($20 million) and higher additions to property, plant and equipment and intangibles ($44 million), partially offset by lower realized gains on financial instruments ($22 million)
Financing activities	**(18)**	(65)	47	Net increased borrowings under credit facilities
Translation of foreign currency cash	**(1)**	-	(1)	
Cash and cash equivalents, end of period	**87**	157	(70)	

9 months ended Sept. 30	2017	2016	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning	**305**	54	251	
Provided by (used in):				
Operating activities	**545**	622	(77)	Unfavourable change in non-cash working capital of ($127 million), partially offset by higher cash earnings ($50 million)
Investing activities	**(214)**	(242)	28	Higher additions to property, plant and equipment and intangibles ($41 million), partially offset by proceeds on sale of Wintering Hills merchant wind facility in the first quarter of 2017 ($61 million) and favourable changes in non-cash investing working capital ($10 million)
Financing activities	**(548)**	(275)	(273)	Higher repayment of long-term debt ($522 million) and lower proceeds on sale of non-controlling interest in subsidiary ($162 million), partially offset by higher borrowings on credit facilities and lower issuance of long-term debt ($303 million), lower dividends paid on common shares ($22 million), and higher realized gains on financial instrument ($106 million)
Translation of foreign currency cash	**(1)**	(2)	1	
Cash and cash equivalents, end of period	**87**	157	(70)	

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 Sept. 30, 2017, we had provided letters of credit totalling $573 million (Dec. 31, 2016 - $566 million) and cash collateral of $56 million (Dec. 31, 2016 - $77 million). This includes $69 million of letters of credit issued by TransAlta Renewables under its uncommitted $100 million demand letter of credit facility. 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.

Commitments

During the first quarter of 2017, we extended and revised our existing agreement with Alstom to provide major maintenance for our Canadian Coal facilities. The agreement relates to major maintenance projects over the 2017 through 2020 years at our Keephills plants and on some Sundance plants. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

Contingencies

I. Line Loss Rule Proceeding

TransAlta is participating in a line loss rule proceeding (the "LLRP") that is currently before the Alberta Utilities Commission (“AUC”). The AUC determined that it had the ability to retroactively adjust line loss rates going back to 2006 and directed the AESO to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. TransAlta may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP, however, currently remains uncertain and the total potential exposure faced by TransAlta, if any, cannot be calculated with certainty until retroactive calculations using a AUC-approved methodology are made available, and until the AUC determines what methodology will be used for retroactive calculations. The AESO expects retroactive calculations for each year using a AUC-approved methodology to begin to be available following the AUC decision on Module C of the LLRP, which is expected to be issued in late 2017. Further, certain PPAs for TransAlta’s facilities provide for the pass through of these types of transmission charges to TransAlta’s buyers or the Balancing Pool.

As a result of the above, no provision has been recorded at this time.

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2016 Annual Integrated Report and Note 8 of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2017 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2016 Annual Integrated Report and Note 9 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, 2016.

During the first quarter of 2017, we discontinued hedge accounting for certain foreign currency cash flow and fair value hedges on US$690 million and US$50 million of debt, respectively. As at March 31, 2017, cumulative gains on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income (“AOCI”) and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. As at March 31, 2017, cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt’s maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

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 Sept. 30, 2017, total Level III financial instruments had a net asset carrying value of $753 million (Dec. 31, 2016 - $758 million net asset). The decrease during the period is primarily due to the weakening of the US dollar relative to the Canadian dollar, settlement of contracts, and partially offset by favourable market price changes in value of the long-term power sale contract designated as an all-in-one cash flow hedge, for which changes in fair value are recognized in other comprehensive income.

2017 Financial Outlook

The following table outlines our expectations on key financial targets for 2017:

Measure	Target
Comparable EBITDA	$1,025 million to $1,100 million
Comparable FFO	$765 million to $820 million
Comparable FCF	$270 million to $310 million
Canadian Coal fleet availability	81 to 83 per cent
Dividend	$0.16 per common share annualized, 15 to 17 per cent payout of FCF

2017 Outlook Update

During the year, emerging labour constraints at our Alberta coal mine have impacted productivity at the mine, significantly reducing our coal inventory and causing coal supply constraints for our facilities in Alberta. The shortfall affected our Sundance coal-fired generating units 1 to 6 and Keephills units 1 to 3. We expect additional mining costs at our Highvale mine operations for the remainder of 2017, and a shorter-term reduction in the power generation at Sundance and Keephills, in order to rebuild our coal inventory. Also, higher productivity capital and higher distributions to non-controlling interests have negatively impacted FCF. In the second quarter we reduced the following 2017 targets: FCF target range to $270 million to $310 million from the previously announced target range of $300 million to $365 million, Comparable EBITDA from the previously announced target range of $1,025 million to $1,135 million to $1,025 to $1,100 million, and FFO from the previously announced target range of $765 million to $855 million to $765 million to $820 million.

Availability

Availability of our Canadian coal fleet is expected to be in range of 81 to 83 per cent in 2017, lower than our target during the first quarter of 2017 of 86 to 88 per cent, due to attrition, unforeseen maintenance, and other issues at the Highvale mine. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent.

Prices

For the remainder of 2017, power prices in Alberta are expected to be higher than 2016 as a result of carbon costs that increase the variable cost of generation year-over-year. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, power prices for the fourth quarter are expected to be comparable to 2016. In Ontario, power prices are expected to be lower due to low demand growth and ample baseload nuclear generation as well as renewable capacity.

Contractual Profile

As a result of the Balancing Pool providing notice of its intention to terminate the Sundance B and C PPAs, effective March 31, 2018, our capacity contracted through PPAs and longer-term contracts in 2018 drops to approximately 55 per cent. As at the end of Sept. 30, 2017, approximately 92 per cent of our 2017 capacity was contracted. The average prices of our short-term physical and financial contracts for 2017 and 2018 are approximately $44 per MWh and $49 per MWh, respectively, in Alberta and approximately US$45 per MWh and US$50 per MWh, respectively, in the Pacific Northwest.

Fuel Costs

As disclosed previously, the cost to mine coal at our Highvale mine is expected to increase due to a major dragline outage and a higher strip ratio in 2017. In addition, we incurred additional costs in the third quarter to mitigate the impact of lower productivity at our mine. These costs are expected to increase our fuel cost by an additional $2 per MWh for the remainder of 2017. Seasonal variations in coal costs at our Highvale mine are minimized through the application of standard costing. Coal costs for 2017, on a standard cost per tonne basis, are expected to be affected lower availability of large equipment. As a result, we now expect our standard coal costs to be 21 per cent higher in 2017, up from the 12 per cent disclosed last quarter. During the third quarter, we successfully implemented a recovery plan and are on track to meet our year-end production target. The development of Pit 9 in 2018 is expected to improve our strip ratio.

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 is expected to increase slightly for the balance of 2017 primarily due to higher transportation costs resulting from higher expected natural gas prices.

Some of our generation from gas is sold under contract with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from third parties 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

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 exposures to maximize earnings while still maintaining an acceptable risk profile. Our revised 2017 target is for Energy Marketing to contribute between $50 million to $70 million in gross margin for the year, down from our $60 million to $70 million target in the first quarter, and below our initial target of $70 million to $90 million.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. 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

Interest expense on debt for 2017 is expected to be higher than in 2016 due mostly to the redemption premium recognized on the early redemption of the CHD debentures, which more than offset the reduction due to lower capitalized interest. During 2016, interest accruals were included relating to our Keephills 1 outage arbitration. 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.

Net Debt, Liquidity, and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.4 billion in liquidity, including the approximate $0.3 billion TransAlta Renewables has available on its committed credit facility. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in 2018.

Capital Expenditures

Our major 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 were in progress in the third quarter are outlined below:

	Total Project		2017[2]		
	Estimated spend	Spent to date[1]	Estimated spend	Target completion date	Details
Project					
South Hedland[3]	556	539	11	Completed July 28, 2017	150 MW combined-cycle power plant
Kent Hills 3 Wind Project[4]	39	3	1	Q4 2018	17.25 MW expansion project located in New Brunswick
Transmission	Not applicable[5]		5	Ongoing	Regulated transmission that receives a return on investment
Total	**595**	**542**	**17**		

Cash required to fund the remainder of the South Hedland power project is expected to be funded by cash generated by our business. The Kent Hills 3 Wind project is expected to be funded by project-level borrowings.

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 property, plant and equipment ("PP&E") and are amortized either on a straight-line basis over the term until the next major maintenance event or on a unit-of-production basis. These costs exclude 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[1]	Expected spend in 2017
Routine capital[6]	Capital required to maintain our existing generating capacity	46	80 - 85
Planned major maintenance	Regularly scheduled major maintenance	105	125 - 130
Mine capital	Capital related to mining equipment and land purchases	9	25 - 30
Finance leases	Payments on finance leases	13	15 - 20
Total sustaining capital		**173**	**245 - 265**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	15	20 - 25
Total sustaining and productivity capital		**188**	**265 - 290**

(1) Represents amounts spent as of Sept. 30, 2017.
(2) Remainder of year.
(3) Estimated project expenditures are AUD$553 million. Total estimated project expenditures are stated in CAD$ and include estimated capital interest costs. The total estimated CAD$ spend has been revised to reflect realized foreign exchange translations. Additional expenditures of $6 million is expected to be incurred in 2018.
(4) Total estimated project spend includes the 17 per cent related to the non-controlling interest share, which will be funded by them.
(5) Transmission projects are aggregated and developed on an ongoing basis. Consequently, discrete project expenditures are not available.
(6) Includes hydro life extension spend.

While we decreased our target for sustaining capital in the second and third quarters, we increased the productivity capital expected spend for 2017, as these expenditures relate to the funding of some Project Greenlight transformation initiatives. In certain cases, payback is expected to be achieved within two years. The total expected spend on sustaining and productivity capital remains unchanged.

To date we have completed major planned outages at Sundance Unit 6, Keephills Unit 2, Keephills Unit 3, Centralia Unit 2, Sarnia and Windsor.

Significant planned major outages remaining for 2017 include the Sheerness 1 outage in the fourth quarter and a major overhaul to one of our draglines at our Highvale mine.

Lost production as a result of planned major maintenance, excluding planned major maintenance for U.S. Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2017:

	Coal	Gas and Renewables	Total	**Lost to date[1]**
GWh lost	940 - 950	235 - 265	1,175 - 1,215	965

Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, existing liquidity, and capital raised from our contracted cash flows. We have access to approximately $1.4 billion in liquidity, if required. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

(1) As at Sept. 30, 2017.
(2) Includes hydro life extension spend.

Accounting Changes

A. Current Accounting Changes

I. Change in Estimates – Useful Lives

As a result of the OCA with the Government of Alberta described in the Significant and Subsequent Events section of this MD&A and in our 2016 annual consolidated financial statements, we will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the nine months ended Sept. 30, 2017 increased by approximately $44 million and the full year 2017 depreciation and amortization expense are expected to increase by approximately $58 million. The useful lives may be revised or extended in compliance with our accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to our decision to retire Sundance Unit 1 effective Jan. 1, 2018, the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the nine months ended Sept. 30, 2017 increased in total by approximately $9 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $15 million.

Since Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, we extended the life of Sundance Unit 2 to 2021 during the third quarter of 2017. As a result, depreciation expense and intangibles amortization for the three months ended Sept. 30, 2017 decreased in total by approximately $2 million and the full year 2017 depreciation and amortization expense is expected to decrease by approximately $4 million.

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by us, include IFRS 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers,* and IFRS 16 *Leases*. Refer to *Note 3* of our most recent annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16. We continue to make progress on the implementation plan for each standard. As part of each implementation plan, a centralized project team has been created to manage project activities. A stakeholder committee has been formed to oversee the implementation process and it includes individuals from the relevant functions and business units.

With respect to IFRS 9, we are in the process of completing its assessment of the classification and measurement portion of the standard. Activities to identify and calculate impacts from the impairment portion of the standard are progressing. In addition, the review of process and disclosure requirements continues. Although work efforts continue, the impacts are not expected to be significant. Our current estimate of the time and effort necessary to complete the implementation plan for IFRS 9 extends into late 2017.

With respect to IFRS 15, we have substantially completed the review and accounting assessment of our revenue streams and underlying contracts with customers and the quantification of impacts will commence in the fourth quarter of 2017. The majority of our revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms. In addition, the review of process and disclosure requirements continues. Commentary on implementation issues specific to the power and utilities industry is in the process of being discussed and issued by standard setters in the United States. This commentary is currently being reviewed in relation to our long-term contracts and other arrangements. We expect to use the modified retrospective method of transition. Under this method, the comparative disclosures presented in the consolidated financial statements as at and for the year ended Dec. 31, 2018 will not be restated. Instead, we will recognize the cumulative impact of the initial application of the standard in retained earnings as at Jan. 1, 2018. Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 will extend into late 2017. It is not yet possible to make a reliable estimate of the impact IFRS 15 will have on the financial statements and disclosures.

We are in the process of completing its initial scoping assessment for IFRS 16 and has prepared a detailed project plan. We anticipate that most of the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

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 U.S. 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.

	Q4 2016	Q1 2017	Q2 2017	**Q3 2017**
Revenues	717	578	503	**588**
Comparable EBITDA	374	274	268	**245**
Comparable FFO	228	203	187	**196**
Net earnings (loss) attributable to common shareholders	61	-	(18)	**(27)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.21	-	(0.06)	**(0.09)**

	Q4 2015	Q1 2016	Q2 2016	Q3 2016
Revenues	595	568	492	620
Comparable EBITDA	268	279	248	244
Comparable FFO	243	196	175	163
Net earnings (loss) attributable to common shareholders	(7)	62	6	(12)
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.02)	0.22	0.02	(0.04)

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:

- U.S. Solar and Wind acquisitions in the third quarter of 2015,
- a recovery of a writedown of deferred tax assets in the first and second quarters of 2016, and the second quarter of 2017,
- effects of unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first, second, and third quarters of 2016, and unrealized gains in the first quarter of 2017,
- effects of the Mississauga cogeneration facility recontracting during the fourth quarter of 2016,
- effects of the Keephills 1 outage provision in the fourth quarter of 2017,
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016, and the Sundance Unit 1 impairment charge during the second quarter of 2017,
- effects of changes in useful lives of certain Canadian Coal assets during the first, second, and third quarters of 2017, and
- effects of an impairment of $114 million in the third quarter of 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

(1) Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934, as amended ("Exchange Act"), are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission. Disclosure controls and procedures 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 the Exchange Act 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. In designing and evaluating our disclosure controls and procedures, 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 management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There have been no changes in our internal control over financial reporting during the three months ended Sept. 30, 2017 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Sept. 30, 2017, the end of the period covered by this report, our disclosure controls and procedures were effective.

TransAlta Corporation
Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2017**	2016	**2017**	2016
Revenues	**588**	620	**1,669**	1,680
Fuel, purchased power, and other	**294**	301	**724**	683
Gross margin	**294**	319	**945**	997
Operations, maintenance, and administration	**119**	119	**371**	364
Depreciation and amortization *(Note 2)*	**158**	145	**455**	414
Asset impairment charge *(Note 3)*	**-**	-	**20**	-
Restructuring	**-**	1	**-**	1
Taxes, other than income taxes	**7**	8	**23**	24
Net other operating income *(Note 4)*	**(10)**	(1)	**(30)**	(1)
Operating income	**20**	47	**106**	195
Finance lease income	**15**	16	**47**	49
Net interest expense *(Note 5)*	**(69)**	(56)	**(190)**	(182)
Foreign exchange gains (losses)	**(8)**	4	**(7)**	(2)
Other income (loss)	**(1)**	1	**1**	1
Earnings (loss) before income taxes	**(43)**	12	**(43)**	61
Income tax recovery *(Note 6)*	**(5)**	(2)	**(41)**	(44)
Net earnings (loss)	**(38)**	14	**(2)**	105
Net earnings (loss) attributable to:				
TransAlta shareholders	**(17)**	(2)	**(25)**	88
Non-controlling interests *(Note 7)*	**(21)**	16	**23**	17
	(38)	14	**(2)**	105
Net earnings (loss) attributable to TransAlta shareholders	**(17)**	(2)	**(25)**	88
Preferred share dividends *(Note 13)*	**10**	10	**20**	32
Net earnings (loss) attributable to common shareholders	**(27)**	(12)	**(45)**	56
Weighted average number of common shares outstanding in the period *(millions)*	**288**	288	**288**	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.09)**	(0.04)	**(0.16)**	0.19

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 2017	3 months ended Sept. 30 2016	9 months ended Sept. 30 2017	9 months ended Sept. 30 2016
Net earnings (loss)	(38)	14	(2)	105
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	14	(4)	2	(40)
Losses on derivatives designated as cash flow hedges, net of tax(2)	(1)	(1)	(1)	-
Total items that will not be reclassified subsequently to net earnings	13	(5)	1	(40)
Gains (losses) on translating net assets of foreign operations(3)	(61)	28	(95)	(101)
Reclassification of translation gains on net assets of divested foreign operations(4)	-	-	(9)	-
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(5)	30	(20)	53	42
Reclassification of (gains) losses on financial instruments designated as hedges of divested foreign operations, net of tax(6)	-	-	14	-
Gains on derivatives designated as cash flow hedges, net of tax(7)	10	54	87	155
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(8)	(18)	(28)	(63)	(16)
Total items that will be reclassified subsequently to net earnings	(39)	34	(13)	80
Other comprehensive income (loss)	(26)	29	(12)	40
Total comprehensive income (loss)	(64)	43	(14)	145
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	(12)	5	(25)	108
Non-controlling interests *(Note 7)*	(52)	38	11	37
	(64)	43	(14)	145

(1) Net of income tax expense of 5 and 1 for the three and nine months ended Sept. 30, 2017 (2016 - 2 and 15 recovery), respectively.

(2) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2017.

(3) Net of income tax recovery of nil and 1 for the three and nine months ended Sept. 30, 2017 (2016 - nil and 10 expense), respectively.

(4) Net of income tax expense of nil and 11 for the three and nine months ended Sept. 30, 2017.

(5) Net of income tax expense of 3 and 5 for the three and nine months ended Sept. 30, 2017 (2016 - 3 recovery and 7 expense), respectively.

(6) Net of income tax recovery of nil and 2 for the three and nine months ended Sept. 30, 2017.

(7) Net of income tax expense of 2 and 53 for the three and nine months ended Sept. 30, 2017 (2016 - 22 and 91 expense), respectively.

(8) Net of income tax expense of 8 and 39 for the three and nine months ended Sept. 30, 2017 (2016 - 11 and 28 expense), respectively.

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2017**	Dec. 31, 2016
Cash and cash equivalents	**87**	305
Trade and other receivables *(Notes 3 and 9)*	**1,114**	703
Prepaid expenses	**33**	23
Risk management assets *(Notes 8 and 9)*	**200**	249
Inventory	**233**	213
Assets held for sale *(Note 3)*	**-**	61
	1,667	1,554
Long-term portion of finance lease receivables	**230**	719
Property, plant, and equipment *(Note 10)*		
Cost	**12,890**	12,773
Accumulated depreciation	**(6,236)**	(5,949)
	6,654	6,824
Goodwill	**463**	464
Intangible assets	**367**	355
Deferred income tax assets	**54**	53
Risk management assets *(Notes 8 and 9)*	**692**	785
Other assets	**234**	242
Total assets	**10,361**	10,996
Accounts payable and accrued liabilities	**511**	413
Current portion of decommissioning and other provisions	**34**	39
Risk management liabilities *(Notes 8 and 9)*	**60**	66
Income taxes payable	**6**	6
Dividends payable *(Note 12)*	**27**	54
Current portion of long-term debt and finance lease obligations *(Note 11)*	**923**	639
	1,561	1,217
Credit facilities, long-term debt, and finance lease obligations *(Note 11)*	**2,857**	3,722
Decommissioning and other provisions	**433**	304
Deferred income tax liabilities	**667**	712
Risk management liabilities *(Notes 8 and 9)*	**38**	48
Defined benefit obligation and other long-term liabilities	**329**	330
Equity		
Common shares *(Note 12)*	**3,094**	3,094
Preferred shares *(Note 13)*	**942**	942
Contributed surplus	**10**	9
Deficit	**(1,056)**	(933)
Accumulated other comprehensive income	**403**	399
Equity attributable to shareholders	**3,393**	3,511
Non-controlling interests *(Note 7)*	**1,083**	1,152
Total equity	**4,476**	4,663
Total liabilities and equity	**10,361**	10,996

Commitments and contingencies *(Note 14)*

Subsequent events *(Note 16)*

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

9 months ended Sept. 30, 2017

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Equity attributable to shareholders	Non-controlling interests	Total
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings (loss)	-	-	-	(25)	-	(25)	23	(2)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	(37)	(37)	-	(37)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	23	23		23
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	2	2	-	2
Intercompany available-for-sale-investments	-	-	-	-	12	12	(12)	-
Total comprehensive income (loss)				(25)	-	(25)	11	(14)
Common share dividends	-	-	-	(24)	-	(24)	-	(24)
Preferred share dividends	-	-	-	(20)	-	(20)	-	(20)
Changes in non-controlling interests in TransAlta Renewables *(Note 7)*	-	-	-	(54)	4	(50)	50	-
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(130)	(130)
Effect of share-based payment plans	-	-	1	-	-	1	-	1
Balance, Sept. 30, 2017	**3,094**	**942**	**10**	**(1,056)**	**403**	**3,393**	**1,083**	**4,476**

9 months ended Sept. 30, 2016

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Equity Attributable to shareholders	Non-controlling interests	Total
Balance, Dec. 31, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings	-	-	-	88	-	88	17	105
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(59)	(59)	-	(59)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	126	126	13	139
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(40)	(40)	-	(40)
Intercompany available-for-sale investments	-	-	-	-	(7)	(7)	7	-
Total comprehensive income				88	20	108	37	145
Common share dividends	-	-	-	(35)	-	(35)	-	(35)
Preferred share dividends	-	-	-	(32)	-	(32)	-	(32)
Changes in non-controlling interests in TransAlta Renewables	-	-	-	(12)	-	(12)	176	164
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(113)	(113)
Common shares issued	18	-	-	-	-	18	-	18
Balance, Sept. 30, 2016	3,093	942	9	(1,009)	373	3,408	1,129	4,537

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2017**	2016	**2017**	2016
Operating activities				
Net earnings (loss)	**(38)**	14	**(2)**	105
Depreciation and amortization *(Note 15)*	**176**	161	**509**	458
Gain (loss) on sale of assets	**1**	(2)	**1**	(1)
Accretion of provisions	**6**	4	**17**	15
Decommissioning and restoration costs settled	**(5)**	(7)	**(12)**	(15)
Deferred income tax recovery *(Note 6)*	**(10)**	(8)	**(58)**	(61)
Unrealized (gains) losses from risk management activities	**(14)**	(1)	**(47)**	19
Unrealized foreign exchange (gains) losses	**13**	(2)	**14**	-
Provisions	**3**	1	**3**	(6)
Asset impairment charges *(Note 3F)*	**-**	-	**20**	-
Other items *(Note 3H)*	**48**	(12)	**93**	(26)
Cash flow from operations before changes in working capital	**180**	148	**538**	488
Change in non-cash operating working capital balances	**21**	80	**7**	134
Cash flow from operating activities	**201**	228	**545**	622
Investing activities				
Additions to property, plant, and equipment *(Note 10)*	**(109)**	(94)	**(266)**	(255)
Additions to intangibles	**(35)**	(6)	**(45)**	(15)
Proceeds on sale of property, plant, and equipment	**1**	3	**1**	4
Proceeds on sale of facility (Wintering Hills) *(Note 3I)*	**-**	-	**61**	-
Realized losses on financial instruments	**-**	(22)	**-**	(5)
Decrease in finance lease receivable	**14**	14	**44**	43
Other	**1**	3	**(1)**	4
Change in non-cash investing working capital balances	**(17)**	3	**(8)**	(18)
Cash flow used in investing activities	**(145)**	(99)	**(214)**	(242)
Financing activities				
Net increase (decrease) in borrowings under credit facilities	**47**	-	**147**	(315)
Repayment of long-term debt	**(1)**	(2)	**(588)**	(66)
Issuance of long-term debt	**-**	-	**-**	159
Dividends paid on common shares *(Note 12)*	**(12)**	(11)	**(35)**	(57)
Dividends paid on preferred shares *(Note 13)*	**(10)**	(10)	**(30)**	(32)
Net proceeds on sale of non-controlling interest in subsidiary	**-**	-	**-**	162
Realized gains (losses) on financial instruments	**-**	-	**107**	-
Distributions paid to subsidiaries' non-controlling interests *(Note 7)*	**(38)**	(35)	**(136)**	(111)
Decrease in finance lease obligation	**(4)**	(4)	**(13)**	(12)
Other	**-**	(3)	**-**	(3)
Cash flow used in financing activities	**(18)**	(65)	**(548)**	(275)
Cash flow from (used in) operating, investing, and financing activities	**38**	64	**(217)**	105
Effect of translation on foreign currency cash	**(1)**	-	**(1)**	(2)
Increase (decrease) in cash and cash equivalents	**37**	64	**(218)**	103
Cash and cash equivalents, beginning of period	**50**	93	**305**	54
Cash and cash equivalents, end of period	**87**	157	**87**	157
Cash income taxes paid	**3**	6	**9**	21
Cash interest paid	**22**	20	**140**	135

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 and on EDGAR at www.sec.gov.

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

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

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

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit and Risk Committee on behalf of the Board of Directors on Oct. 31, 2017.

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 for information regarding judgments and estimates.

2. Significant Accounting Policies

A. Current Accounting Changes

I. Change in Estimates – Useful Lives

As a result of the Off-Coal Arrangement ("OCA") with the Government of Alberta described in Note 4(A) of the Corporation's most recent annual consolidated financial statements, the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the Property, Plant, and Equipment ("PP&E") and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the nine months ended Sept. 30, 2017 increased in total by approximately $44 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 3G for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the nine months ended Sept. 30, 2017 increased in total by approximately $15 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $26 million.

Since Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the life of Sundance Unit 2 to 2021. As a result, depreciation expense and intangibles amortization for the three months ended Sept. 30, 2017 decreased in total by approximately $2 million and the full year 2017 depreciation and amortization expense is expected to decrease by approximately $4 million.

B. Future Accounting Changes

Accounting standards that have been previously issued by the International Accounting Standards Board ("IASB") but are not yet effective, and have not been applied by the Corporation, include International Financial Reporting Standards ("IFRS") 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers,* and IFRS 16 *Leases*. Refer to *Note 3* of the Corporation's most recent annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16. The Corporation continues to make progress on its implementation plan for each standard. As part of each implementation plan, a centralized project team has been created to manage project activities. A stakeholder committee has been formed to oversee the implementation process and it includes individuals from the relevant functions and business units.

With respect to IFRS 9, the Corporation is in the process of completing its assessment of the classification and measurement portion of the standard. Activities to identify and calculate impacts from the impairment portion of the standard are progressing. In addition, the review of process and disclosure requirements continues. Although work efforts continue, the impacts are not expected to be significant. The Corporation's current estimate of the time and effort necessary to complete the implementation plan for IFRS 9 extends into late 2017.

With respect to IFRS 15, the Corporation has substantially completed the review and accounting assessment of its revenue streams and underlying contracts with customers and the quantification of impacts will commence in the fourth quarter of 2017. The majority of the Corporation's revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms. In addition, the review of process and disclosure requirements continues. Commentary on implementation issues specific to the power and utilities industry is in the process of being discussed and issued by standard setters in the United States. This commentary is currently being reviewed in relation to the Corporation's long-term contracts and other arrangements. The Corporation expects to use the modified retrospective method of transition. Under this method, the comparative disclosures presented in the consolidated financial statements as at and for the year ended Dec. 31, 2018 will not be restated. Instead, the Corporation will recognize the cumulative impact of the initial application of the standard in retained earnings as at Jan. 1, 2018. The Corporation's current estimate of the time and effort necessary to complete the Corporation's implementation plan for IFRS 15 will extend into late 2017. It is not yet possible to make a reliable estimate of the impact IFRS 15 will have on the financial statements and disclosures.

The Corporation is in the process of completing its initial scoping assessment for IFRS 16 and has prepared a detailed project plan. The Corporation anticipates that most of the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on the Corporation's financial statements and disclosures.

C. Comparative Figures

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

3. Significant Events

A. Balancing Pool Provides Notice to Terminate the Sundance Alberta 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 Power Purchase Arrangements ("Sundance PPAs") effective March 31, 2018.

The termination of the Sundance PPAs by the Balancing Pool was expected and the Corporation anticipates working closely with the Balancing Pool to ensure the company receives the termination payment that it believes it is entitled to under the Sundance PPAs and applicable legislation. The expected impacts of the termination include approximately $215 million in compensation for the net book value of the assets as compared to the Balancing Pool's estimate of approximately $157 million. The Balancing Pool's estimate differs because it excludes certain mining assets which the Corporation believes should be included in the net book value calculation.

B. Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, the Corporation announced that the minimum election notices received did not meet the requirements required to give effect to the conversion of Series E Preferred Shares into Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and the dividend rate will remain fixed for the subsequent five-year period. See Note 13 for further details.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements required to give effect to the conversion of Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and the dividend will remain fixed for the subsequent five-year period. See Note 13 for further details.

C. South Hedland Facility Reaches Commercial Operation

The South Hedland facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, Fortescue Metals Group Ltd. ("FMG") notified the Corporation that, in its view, the South Hedland facility had not yet satisfied the requisite performance criteria under the South Hedland power purchase agreement between the Corporation and FMG. The Corporation's view is that all the conditions to establishing that commercial operations have been achieved under the terms of the power purchase agreement with FMG have been satisfied in full. Horizon Power has not disputed commercial operation.

D. Termination of Solomon Power Purchase Agreement

On Aug. 1, 2017, the Corporation received notice that FMG intends to repurchase the Solomon Power facility from TEC Pipe Pty Ltd., a wholly-owned subsidiary of the Corporation, for approximately US$335 million. FMG is expected to complete its acquisition of the Solomon Power Station in November 2017. Accordingly, the Corporation reclassified the long-term portion of finance lease receivable within Trade and other receivables on the Condensed Consolidated Statements of Financial Position.

E. Kent Hills 3 Wind Project

During the second quarter of 2017, TransAlta Renewables Inc. ("TransAlta Renewables") entered into a long-term contract with New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 wind project.

This is an expansion of our existing Kent Hills wind farms, increasing the total operating capacity of the Kent Hills wind farms to approximately 167 MW. As part of the regulatory process, the Corporation submitted an Environmental Impact Assessment to the Province of New Brunswick in the third quarter of 2017. Provided environmental approvals are received, the Corporation expects to begin the construction phase in the spring of 2018.

At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035 matching the life of Kent Hills 2 and Kent Hills 3 wind projects.

F. Transition to Clean Power in Alberta and Impairment Charge

On April 19, 2017, the Corporation announced its strategy to accelerate its transition to gas and renewables generation. The strategy includes the following steps:

- retirement of Sundance Unit 1 effective Jan. 1, 2018;
- mothballing of Sundance Unit 2 effective Jan. 1, 2018, for a period of 2 years; and
- conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2023 timeframe, thereby extending the useful lives of these units until the mid-2030's.

Sundance Units 1 and 2

Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide the Corporation with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively comprise 560 MW of the 2,141 MW at the Sundance power plant, which serves as a baseload provider for the Alberta electricity system. The Power Purchase Arrangement ("PPA") with the Balancing Pool relating to Sundance Units 1 and 2 expires on Dec. 31, 2017.

In the second quarter of 2017, the Corporation recognized an impairment loss on Sundance Unit 1 in the amount of $20 million due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintains the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant cash-generating unit to 2021.

G. Change in Credit Ratings

The Corporation maintains investment grade ratings from three credit rating agencies.

On March 15, 2017, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable.

On April 3, 2017, DBRS Limited changed the Corporation's Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating BBB to BBB (low). The trends on the above-mentioned ratings were changed to stable from negative.

On April 11, 2017, Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- but changed the outlook from stable to negative.

H. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced that it had signed a Non-Utility Generator Contract (the "NUG Contract") with the Ontario's Independent Electricity System Operator for its Mississauga cogeneration facility. The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018.

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in Ontario. For the three and nine months ended Sept. 30, 2017, $22 million and $71 million, respectively, of cash receipts related to the contractual monthly payments were included in the line entitled "other items" in arriving at cash flow from operations before changes in working capital in the cash flow statement.

As outlined in Note 8A of the 2016 Consolidated Financial Statements, the Corporation recognized a pre-tax gain of approximately $191 million in 2016 and also recognized $46 million in accelerated depreciation. As a result, over the duration of the NUG Contract, the Corporation does not expect to recognize any further net earnings impacts. However, the Corporation's cash flow from operating activities will include the contractual monthly payments received under the NUG Contract.

I. Wintering Hills Sale

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale closed March 1, 2017.

J. Preferred Share Exchange

On Feb. 10, 2017, the Corporation announced that it would not proceed with the transaction previously announced on Dec. 19, 2016, pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares in the capital of the Corporation.

4. Net Other Operating Income (Loss)

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into the OCA with the Government of Alberta on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $39.7 million ($37.2 million, net to the Corporation), commencing Jan. 1, 2017 and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Accordingly, during the three and nine months ended Sept. 30, 2017, approximately $10 million and $30 million, respectively, was recognized in Net Other Operating Income in the Condensed Consolidated Statement of Earnings. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions.

5. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Interest on debt	**53**	59	**165**	170
Interest income	**(1)**	-	**(3)**	(1)
Capitalized interest	**(2)**	(4)	**(10)**	(11)
Loss on redemption of bonds *(Note 11)*	**6**	-	**6**	1
Interest on finance lease obligations	**1**	1	**3**	3
Other(1)	**6**	(4)	**13**	5
Accretion of provisions	**6**	4	**16**	15
Net interest expense	**69**	56	**190**	182

(1) 2016 includes interest accrued related to the Keephills 1 outage.

6. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Current income tax expense	**5**	6	**17**	17
Adjustments in respect of deferred income tax of prior periods	**-**	1	**-**	1
Deferred income tax recovery related to the origination and reversal of temporary differences	**(14)**	(14)	**(35)**	(25)
Deferred income tax expense related to temporary difference on investment in subsidiary	**-**	-	**-**	3
Deferred income tax expense resulting from changes in tax rates or laws	**-**	-	**-**	1
Deferred income tax expense (recovery) arising from the reversal of writedown of deferred income tax assets[1]	**4**	5	**(23)**	(41)
Income tax recovery	**(5)**	(2)	**(41)**	(44)

(1) During the three months ended Sept. 30, 2017, the Corporation recorded a $4 million writedown of deferred income tax assets, and during the nine months ended Sept. 30, 2017, the Corporation reversed a previous writedown of deferred income tax assets of $23 million. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. Recognized other comprehensive income during the period has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Current income tax expense	**5**	6	**17**	17
Deferred income tax recovery	**(10)**	(8)	**(58)**	(61)
Income tax recovery	**(5)**	(2)	**(41)**	(44)

7. 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 the 150 MW Kent Hills wind farm located in New Brunswick.

The South Hedland facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to by TransAlta Renewables.

The Corporation's share of ownership and equity participation in TransAlta Renewables during the nine months ended Sept. 30, 2017 and 2016 is as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1 2017 and thereafter	64.0	64.0

Amounts attributable to non-controlling interests are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Net earnings (loss)				
TransAlta Cogeneration L.P.	**3**	7	**25**	26
TransAlta Renewables	**(24)**	9	**(2)**	(9)
	(21)	16	**23**	17
Total comprehensive income (loss)				
TransAlta Cogeneration L.P.	**3**	9	**25**	39
TransAlta Renewables	**(55)**	29	**(14)**	(2)
	(52)	38	**11**	37
Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**16**	14	**72**	49
TransAlta Renewables	**22**	21	**64**	62
	38	35	**136**	111

As at	Sept. 30, 2017	Dec. 31, 2016
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**256**	301
TransAlta Renewables	**827**	851
	1,083	1,152
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**36.0**	40.2

8. Financial Instruments

A. Financial Assets and Liabilities – Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, 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 unadjusted quoted prices 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 and liabilities and long-term debt measured and carried at fair value, 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 set out below, and excludes the effects on fair value of observable 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	Sept. 30, 2017		Dec. 31, 2016	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	857	+134 -134	907	+75 -69
Long-term power sale - Alberta	1	+2 -2	(3)	+5 -5
Unit contingent power purchases	10	+3 -4	13	+2 -4
Structured products - Eastern U.S.	24	+7 -8	24	+8 -8
Others	3	+4 -4	6	+3 -3

i. Long-Term Power Sale - U.S.

The Corporation has a long-term fixed price power sale contract in the U.S. 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 beyond September 2019, 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 averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per Megawatt hour ("MWh") used in determining the Level III base fair value at Sept. 30, 2017 are US$23 - US$33 (Dec. 31, 2016 - US$27 - US$36). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2016 – US$5) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2016 to Sept. 30, 2017, the base fair value and the sensitivity values have decreased by $73 million and $9 million, respectively.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as held for trading.

For periods beyond 2022, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high, and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at Sept. 30, 2017 are $63 - $67 (Dec. 31, 2016 - $68 - $93). The sensitivity analysis for both periods has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. 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 held for trading.

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 Sept. 30, 2017 are nil (Dec. 31, 2016 – nil) and 1.69 per cent to 2.76 per cent (Dec. 31, 2016 – 2.15 per cent to 3.62 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 0.93 per cent to 1.09 per cent (Dec. 31, 2016 – 0.75 per cent) and a change in volumetric discount rates of approximately 7.68 per cent to 9.74 per cent (Dec. 31, 2016 – 15.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern U.S.

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 Sept. 30, 2017 are 69 per cent to 157 per cent and 73 per cent to 88 per cent (Dec. 31, 2016 – 66 per cent to 128 per cent and 65 per cent to 88 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 5 per cent (Dec. 31, 2016 – 5 per cent) and a change in non-standard shape factors of approximately 6 per cent (Dec. 31, 2016 – 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 Sept. 30, 2017 are 17 per cent to 49 per cent and 70 per cent (Dec. 31, 2016 – 20 per cent to 54 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 and correlation of approximately 30 and 32 per cent (Dec. 31, 2016 – 10 per cent), respectively.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Sept. 30, 2017 are as follows: Level I - $4 million net liability (Dec. 31, 2016 – nil), Level II - $1 million net asset (Dec. 31, 2016 - $14 million net liability), Level III - $753 million net asset (Dec. 31, 2016 – $758 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 2017 are primarily attributable to the changes in value of the long-term power sale contract (Level III hedge) as discussed in the preceding section (B)(I)(c)(i) of this note.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities during the nine months ended Sept. 30, 2017 and 2016, respectively:

	9 months ended Sept. 30, 2017			9 months ended Sept. 30, 2016		
	Hedge	Non-Hedge	Total	Hedge	Non-Hedge	Total
Opening balance	726	32	758	640	(98)	542
Changes attributable to:						
Market price changes on existing contracts	95	1	96	172	20	192
Market price changes on new contracts	-	1	1	-	9	9
Contracts settled	(39)	(4)	(43)	(13)	78	65
Change in foreign exchange rates	(58)	(1)	(59)	(57)	2	(55)
Net risk management assets at end of period	724	29	753	742	11	753
Additional Level III information:						
Gains recognized in Other Comprehensive Income	37	-	37	115	-	115
Total gains included in earnings before income taxes	39	1	40	13	31	44
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	-	(3)	(3)	-	109	109

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 $43 million as at Sept. 30, 2017 (Dec. 31, 2016 - $176 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended Sept. 30, 2017 are primarily attributable to the settlement of contracts.

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow and fair value hedges on US$690 million and US$50 million of debt, respectively. The cumulative losses on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. The cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt's maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

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				Total carrying
	Level I	Level II	Level III	Total	value
Long-term debt - Sept. 30, 2017	**-**	**3,769**	**-**	**3,769**	**3,715**
Long-term debt[1] - Dec. 31, 2016	-	4,271	-	4,271	4,221

(1) Includes current portion and excludes $67 million of debt measured and carried at fair value.

The fair values of the Corporation's debentures and senior notes 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.

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:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	**2017**	2016
Unamortized net gain at beginning of period	**113**	157	**148**	202
New inception gains	**5**	3	**9**	7
Change in foreign exchange rates	**(4)**	2	**(8)**	(9)
Amortization recorded in net earnings during the period	**(8)**	(12)	**(43)**	(50)
Unamortized net gain at end of period	**106**	150	**106**	150

9. Risk Management Activities

A. Net Risk Management Assets and Liabilities

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

As at Sept. 30, 2017

	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	94	-	8	102
Long-term	648	-	1	649
Net commodity risk management assets	742	-	9	751
Other				
Current	(1)	-	39	38
Long-term	-	-	5	5
Net other risk management assets (liabilities)	(1)	-	44	43
Total net risk management assets	741	-	53	794

As at Dec. 31, 2016

	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	86	-	(16)	70
Long-term	683	-	(9)	674
Net commodity risk management assets (liabilities)	769	-	(25)	744
Other				
Current	105	-	8	113
Long-term	59	3	1	63
Net other risk management assets	164	3	9	176
Total net risk management assets (liabilities)	933	3	(16)	920

B. 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 14(b) 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.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2017, associated with the Corporation's proprietary trading activities was $2 million (Dec. 31, 2016 - $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.

VaR at Sept. 30, 2017, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $10 million (Dec. 31, 2016 - $19 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2017, associated with these transactions was $3 million (Dec. 31, 2016 - $7 million).

b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the U.S. dollar, and the Australian dollar, 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 14(B)(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 Sept. 30, 2017:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1,2]	54	46	100	1,114
Long-term finance lease receivables	95	5	100	230
Risk management assets[1]	99	1	100	892
Total				2,236

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The Corporation has a non-investment grade customer whose outstanding balance accounted for $435 million (Dec. 31, 2016 - $445 million). As a result of the termination of the Solomon Power Purchase Arrangement (see Note 3), the Corporation expects to receive payment of the $412 million finance lease receivable balance in November 2017. The Corporation had two investment grade customers whose outstanding balance each accounted for greater than 10 per cent of trade accounts receivable outstanding. The Corporation has evaluated the risk of default related to these customers to be minimal.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at Sept. 30, 2017, was $16 million (Dec. 31, 2016 - $14 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 Sept. 30, 2017, TransAlta maintains investment grade ratings from three credit rating agencies (See Note 3H). TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

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

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Accounts payable and accrued liabilities	511	-	-	-	-	-	511
Long-term debt(1)	238	710	460	460	209	1,664	3,741
Commodity risk management assets	(40)	(86)	(88)	(78)	(94)	(365)	(751)
Other risk management assets	(5)	(38)	-	-	-	-	(43)
Finance lease obligations	4	15	12	9	6	19	65
Interest on long-term debt and finance lease obligations(2)	71	168	143	115	93	715	1,305
Dividends payable	27	-	-	-	-	-	27
Total	806	769	527	506	214	2,033	4,855

(1) Excludes impact of hedge accounting.
(2) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

C. Collateral and Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. 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 Sept. 30, 2017, the Corporation had posted collateral of $106 million (Dec. 31, 2016 - $116 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $63 million (Dec. 31, 2016 - $49 million) of collateral to its counterparties.

10. 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(1)	Total
As at Dec. 31, 2016	95	2,664	498	2,290	606	407	264	6,824
Additions	-	-	-	-	-	261	5	266
Additions - finance lease	-	1	-	-	5	-	-	6
Disposals	-	-	(3)	-	-	-	-	(3)
Asset impairment charges *(Note 3)*	-	(20)	-	-	-	-	-	(20)
Depreciation	-	(260)	(47)	(92)	(52)	-	(14)	(465)
Revisions and additions to decommissioning and restoration costs	-	73	10	11	33	-	(1)	126
Retirement of assets and disposals	-	(7)	(1)	-	(3)	-	(1)	(12)
Change in foreign exchange rates	(1)	(25)	1	(21)	(3)	(3)	(4)	(56)
Transfers(2)	1	98	459	13	10	(575)	(18)	(12)
As at Sept. 30, 2017	95	2,524	917	2,201	596	90	231	6,654

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventative or planned maintenance.
(2) During the second quarter of 2017, the Corporation reclassified approximately $13 million of capital spares and other assets to inventory.

11. Credit Facilities, Long-Term Debt, and Finance Lease Obligations

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at	Sept. 30, 2017			Dec. 31, 2016		
	Carrying value	Face value	Interest[(1)]	Carrying value	Face value	Interest[(1)]
Credit facilities	147	147	2.7%	-	-	-
Debentures[(2)]	1,046	1,051	6.0%	1,045	1,051	6.0%
Senior notes	1,482	1,494	6.0%	2,151	2,158	5.0%
Non-recourse[(3)]	994	997	4.5%	1,038	1,048	4.5%
Other[(4)]	46	46	9.1%	54	54	9.2%
	3,715	3,735		4,288	4,311	
Finance lease obligations	65			73		
	3,780			4,361		
Less: current portion of long-term debt	(907)			(623)		
Less: current portion of finance lease obligations	(16)			(16)		
Total current long-term debt and finance lease obligations	(923)			(639)		
Total credit facilities, long-term debt, and finance lease obligations	2,857			3,722		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) U.S. face value at Sept. 30, 2017 - US$1.2 billion (Dec. 31, 2016 - US$1.6 billion).
(3) Includes US$48 million at Sept. 30, 2017 (Dec. 31, 2016 - US$53 million).
(4) Includes US$26 million at Sept. 30, 2017 (Dec. 31, 2016 - US$29 million) of tax equity financing.

Subsequent to the third quarter of 2017:

- TransAlta Renewables closed a $260 million bond offering on Oct. 2, 2017, by way of a private placement. See Note 16 for further details.
- The Corporation early redeemed the $191 million face value Canadian Hydro Developers, Inc. ("CHD") non-recourse debentures on Oct. 12, 2017. See Note 16 for further details.

During the first half of 2017:

- the Corporation repaid a US$400 million US Senior Note on maturity. The repayment was hedged with a cross currency swap. The maturity value of the bond was $434 million;
- TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The agreement is fully committed for four years, expiring in 2021. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the new credit agreement, the $350 million credit facility provided by TransAlta was cancelled. The Corporation's consolidated liquidity remains unchanged, as the Corporation's credit facility decreased by $500 million to $1 billion in total, while TransAlta Renewables' facility increased to a total of $500 million.

The Corporation has a total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $500 million. In total, $1.3 billion (Dec. 31, 2016 - $1.4 billion) is not drawn. At Sept. 30, 2017, the $0.7 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.1 billion (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, the Corporation also has $87 million of available cash and cash equivalents.

The Corporation had total outstanding letters of credit as at Sept. 30, 2017 was $573 million (Dec. 31, 2016 - $566 million) with no (Dec. 31, 2016 - nil) amounts exercised by third parties under these arrangements including TransAlta Renewables outstanding letters of credit of $69 million (Dec. 31, 2016 – nil). 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 Sept. 30, 2017, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of $197 million (Dec. 31, 2016 - $193 million) issued by the Corporation's subsidiary, Canadian Hydro Developers, Inc. ("CHD"), include restrictive covenants requiring the cash proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures. On Oct. 12, 2017, these non-recourse debentures were redeemed, with a face value of $191 million.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond and Mass Solar non-recourse bonds 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 third quarter. However, funds in these entities that have accumulated since the third quarter test, will remain there until the next debt service coverage ratio can be calculated in the fourth quarter of 2017. At Sept. 30, 2017, $26 million (Dec. 31, 2016 - $24 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 Sept. 30, 2017. However, as at Sept. 30, 2017, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letter of credits and was not available for general use.

C. Security

Non-recourse debts of $613 million in total (Dec. 31, 2016 - $644 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of $918 million at Sept. 30, 2017 (Dec. 31, 2016 - $956 million). At Sept. 30, 2017, a non-recourse bond of approximately $183 million (Dec. 31, 2016 - $201 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

12. Common Shares

A. Issued and Outstanding

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

	3 months ended Sept. 30				9 months ended Sept. 30			
	2017		2016		2017		2016	
	Common shares (millions)	Amount	Common shares (millions)	Amount	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	287.9	3,095	287.9	3,095	287.9	3,095	284.0	3,077
Issued under the dividend reinvestment and optional common share purchase plan	-	-	-	-	-	-	3.9	18
	287.9	3,095	287.9	3,095	287.9	3,095	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	-	(1)	-	(2)	-	(1)	-	(2)
Issued and outstanding, end of period	287.9	3,094	287.9	3,093	287.9	3,094	287.9	3,093

B. Dividends

On Oct. 30, 2017, the Corporation declared a dividend of $0.04 per common share, payable on Jan. 1, 2018.

On July 18, 2017, the Corporation declared a dividend of $0.04 per common share, payable on Oct. 1, 2017.

On April 19, 2017, the Corporation declared a dividend of $0.04 per common share, payable on July 1, 2017.

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

C. Stock Options

In March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance.

In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance.

13. 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 Sept. 30, 2017 and Dec. 31, 2016, the Corporation had 10.2 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares issued and outstanding and 1.8 million Series B Cumulative Redeemable Floating Rate First Preferred Shares issued and outstanding.

B. Dividends

The following table summarizes the preferred share dividends declared within the three and nine months ended Sept. 30:

		3 months ended Sept. 30		9 months ended Sept. 30	
	Quarterly amounts	**2017**	2016	**2017(1)**	2016
Series	per share	**Total**	Total	**Total**	Total
A	0.16931(2)	**2**	1	**3**	6
B	0.16125(3)	**-**	-	**1**	1
C	0.25169(4)	**3**	4	**6**	10
E	0.3125(5)	**3**	2	**6**	8
G	0.33125	**2**	3	**4**	7
Total for the period		**10**	10	**20**	32

(1) No dividends were declared in the first quarter, as on Dec. 19, 2016, the quarterly dividend related to the period covering the first quarter of 2017 was declared.
(2) Dividends on the Series A Preferred Shares for the first quarter of 2016 were $0.2875 per share.
(3) 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. The Series B Preferred Shares were issued on March 17, 2016.
(4) The quarterly dividend rate for the Series C Preferred Shares for the five-year period from and including June 30, 2017 to, but excluding June 30, 2022, will be $0.25169 following the rate reset of the Series C Preferred Shares effective June 30, 2017.
(5) The quarterly dividend rate for the Series E Preferred Shares for the five-year period from and including Sept. 30, 2017 to, but excluding Sept. 30, 2022, will be $0.32463 following the rate reset of the Series E Preferred Shares effective Sept. 30, 2017.

On Sept. 17, 2017, the Corporation announced that after taking into account all election notices received by the Sept. 15, 2017 deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017 to, but excluding Sept. 30, 2022, will be 5.194 per cent, being equal to the five-year Government of Canada bond yield of 1.544 per cent determined as of Aug. 31, 2017, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

On June 16, 2017, the Corporation announced that after taking into account all election notices received by the June 15, 2017 deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017 to, but excluding June 30, 2022, will be 4.027 per cent, being equal to the five-year Government of Canada bond yield of 0.927 per cent determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

On Oct. 30, 2017, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A Preferred shares, $0.17467 per share on the Series B Preferred Shares, $0.25169 per share on the Series C shares, $0.32463 per share on the Series E shares, and $0.33125 per share on the Series G Preferred shares, all payable on Dec. 31, 2017.

14. Commitments and Contingencies

A. Commitments

During the first quarter of 2017, the Corporation extended and revised its existing agreement with Alstom to provide major maintenance for the Corporation's Canadian Coal facilities. The agreement relates to major maintenance projects over the 2017 through 2020 years at the Corporation's Keephills plants and on some Sundance plants. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance.

B. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation is participating in a line loss rule proceeding (the "LLRP") that is currently before the Alberta Utilities Commission ("AUC"). The AUC determined that it had the ability to retroactively adjust line loss rates going back to 2006 and directed the Alberta Electric System Operator (the "AESO") to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. The Corporation may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP, however, currently remains uncertain and the total potential exposure faced by the Corporation, if any, cannot be calculated with certainty until retroactive calculations using a AUC-approved methodology are made available, and until the AUC determines what methodology will be used for retroactive calculations. The AESO expects retroactive calculations for each year using a AUC-approved methodology to begin to be available following the AUC decision on Module C of the LLRP, which is expected to be issued in late 2017. Further, certain PPAs for the Corporation's facilities provide for the pass through of these types of transmission charges to the Corporation's buyers or the Balancing Pool.

As a result of the above, no provision has been recorded at this time.

15. Segment Disclosures

A. Reported Segment Earnings (Loss)

I. Earnings Information

3 months ended Sept. 30, 2017	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	252	147	56	43	42	31	17	-	588
Fuel and purchased power	154	109	24	3	2	2	-	-	294
Gross margin	98	38	32	40	40	29	17	-	294
Operations, maintenance, and administration	42	13	10	9	12	10	5	18	119
Depreciation and amortization	79	19	10	10	27	7	-	6	158
Taxes, other than income taxes	3	1	-	-	2	-	-	1	7
Net other operating income	(10)	-	-	-	-	-	-	-	(10)
Operating income (loss)	(16)	5	12	21	(1)	12	12	(25)	20
Finance lease income	-	-	2	13	-	-	-	-	15
Net interest expense									(69)
Foreign exchange loss									(8)
Other loss									(1)
Loss before income taxes									(43)

3 months ended Sept. 30, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	253	143	99	30	49	30	16	-	620
Fuel and purchased power	121	121	49	5	3	2	-	-	301
Gross margin	132	22	50	25	46	28	16	-	319
Operations, maintenance, and administration	45	14	13	6	13	8	6	14	119
Depreciation and amortization	59	25	12	5	29	7	1	7	145
Restructuring provision	-	-	-	-	-	-	-	1	1
Taxes, other than income taxes	4	1	-	-	2	1	-	-	8
Net other operating income	-	-	-	-	(1)	-	-	-	(1)
Operating income (loss)	24	(18)	25	14	3	12	9	(22)	47
Finance lease income	-	-	3	13	-	-	-	-	16
Net interest expense									(56)
Foreign exchange gain									4
Other income									1
Earnings before income taxes									12

9 months ended Sept. 30, 2017	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	750	294	209	97	188	95	36	-	1,669
Fuel and purchased power	434	188	78	9	10	5	-	-	724
Gross margin	316	106	131	88	178	90	36	-	945
Operations, maintenance, and administration	133	37	36	22	36	27	16	64	371
Depreciation and amortization	226	50	28	24	82	24	1	20	455
Asset impairment	20	-	-	-	-	-	-	-	20
Taxes, other than income taxes	10	3	1	-	6	2	-	1	23
Net other operating income	(30)	-	-	-	-	-	-	-	(30)
Operating income (loss)	(43)	16	66	42	54	37	19	(85)	106
Finance lease income	-	-	8	39	-	-	-	-	47
Net interest expense									(190)
Foreign exchange loss									(7)
Other income									1
Loss before income taxes									(43)

9 months ended Sept. 30, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	716	240	292	89	188	96	59	-	1,680
Fuel and purchased power	324	196	126	16	15	6	-	-	683
Gross margin	392	44	166	73	173	90	59	-	997
Operations, maintenance, and administration	133	38	41	18	39	25	20	50	364
Depreciation and amortization	184	49	40	11	88	20	2	20	414
Restructuring provision	-	-	-	-	-	-	-	1	1
Taxes, other than income taxes	10	3	1	-	6	3	-	1	24
Net other operating (income) loss	-	-	-	-	(1)	-	-	-	(1)
Operating income (loss)	65	(46)	84	44	41	42	37	(72)	195
Finance lease income	-	-	10	39	-	-	-	-	49
Net interest expense									(182)
Foreign exchange loss									(2)
Other income									1
Earnings before income taxes									61

Included in revenues of the Wind and Solar Segment for the three and nine months ended Sept. 30, 2017 are $3 million (2016 - $4 million) and $13 million (2016 - $14 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

During the three and nine months ended Sept. 30, 2016, the Corporation recorded a $5 million writedown and $9 million writedown, respectively, of coal inventory to its net realizable value. The writedown were included in fuel and purchased power of the U.S. Coal Segment.

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

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2017	2016	2017	2016
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings (Loss)	158	145	455	414
Depreciation included in fuel and purchased power	18	16	54	44
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	176	161	509	458

16. Subsequent Events

A. TransAlta Renewables $260 Million Project Financing of New Brunswick Wind Assets and Early Redemption of CHD's Outstanding Debentures

On Sept. 27, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, Kent Hills Wind LP ("KHWLP"), priced an approximate $260 million bond offering, by way of a private placement, secured by, among other things, a first ranking charge over all assets of KHWLP. The offering closed on Oct. 2, 2017. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly and maturing Nov. 30, 2033. Net proceeds will be used to fund a portion of the construction costs for the 17.25 MW Kent Hills expansion (upon meeting certain completion tests and other specified conditions) and to make advances to CHD and to Natural Forces Technologies Inc., KHWLP's partner which owns approximately 17 per cent of KHWLP.

At the same time, CHD, the Corporation's subsidiary, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June of 2018. On Oct. 12, 2017, the Corporation redeemed the unsecured debentures for $201 million in total, comprised of principal of $191 million, an early redemption premium of $6 million, and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the three and nine months ended Sept. 30, 2017.

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 "Condensed Consolidated Financial Statements".

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the nine months ended Sept. 30, 2017:

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

1.37 times [(1)]

(1) Last 12 months. Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Supplemental Information

		Sept. 30, 2017	Dec. 31, 2016
Closing market price (TSX) ($)		7.30	7.43
Price range for the last 12 months (TSX) ($)	High	8.31	7.54
	Low	5.17	3.76
Adjusted net debt to invested capital[1] (%)		50.8	51.0
Adjusted net debt to comparable EBITDA[1, 2] (times)		3.6	3.8
Return on equity attributable to common shareholders[2] (%)		0.8	5.4
Return on capital employed[2] (%)		4.3	5.3
Earnings coverage[2] (times)		1.3	1.7
Dividend payout ratio based on FFO[1, 2, 3] (%)		5.9	7.8
Dividend coverage[2,3] (times)		15.3	11.5
Dividend yield[2,3] (%)		2.2	4.0
Adjusted FFO to adjusted net debt[2] (%)		19.2	17.0
FFO before interest to adjusted interest coverage[2] (times)		4.1	3.8

Ratio Formulas

Adjusted net debt to invested capital = long-term debt and finance 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

Adjusted net debt to comparable EBITDA = long-term debt and finance 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

Return on equity attributable to common shareholders = net earnings attributable to common shareholders / equity attributable to shareholders excluding AOCI – issued preferred shares

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

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

(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 Additional IFRS and Non-IFRS Measures section of this MD&A.

(2) Last 12 months.

(3) On Jan. 14, 2016, we revised our dividend to $0.16 per common share on an annualized basis from $0.72 previously. The effect of the change is not reflected in these historical ratios.

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

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

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

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

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

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.

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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