TransAlta Corporation
Second Quarter Report for 2016

Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and six months ended June 30, 2016 and 2015, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2015 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 June 30, 2016. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Aug. 8, 2016. 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 in our Condensed Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2016, and 2015. 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. See the Comparable Funds from Operations and Comparable Free Cash Flow, Discussion of Segmented Comparable Results, and Earnings and Other Measures on a Comparable Basis 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, including the 2016 Financial Outlook section of this MD&A, 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 major projects such as the South Hedland power project, and their attendant costs; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, mining costs, fuel costs, capital spending, and maintenance, and the variability of these costs and spending; expected decommissioning costs; the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2016 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), comparable free cash flow ("FCF"), and expected sustaining capital expenditures for 2016); expectations in respect of financial ratios and targets (including comparable FFO before interest to adjusted interest coverage, adjusted comparable FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); expectations regarding our ability to meet key financial ratios and targets; expected governmental regulatory regimes and legislation (including the Government of Alberta's Climate Leadership Plan, the Government of Ontario's greenhouse gas cap and trade program and the U.S. Clean Power Plan) and their expected impact on TransAlta and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the outcome of discussions with the Government of Alberta in relation to coal-fired generation transition under the Climate Leadership Plan; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term; expectations in relation to electricity prices; expectations regarding contracted cash flows; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expected financing of our capital expenditures; expectations regarding the refinancing of debt maturities; expectations regarding the use of free cash flow to be primarily allocated to debt reduction; ability to execute on our de-leveraging strategy; our trading strategies and the risks involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; our expectations on dividend payments; 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; the estimated contribution of Energy Marketing activities to gross margin; expectations regarding our continued ownership of TransAlta Renewables Inc. ("TransAlta Renewables"); expectations on, the impact of, the potential transfer of the Alberta Power Purchase Arrangements ("PPA") to the Balancing Pool; and expectations of the financial impact of our agreement with the Government of Alberta in respect of flood and drought mitigation.

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, including the outcome of our negotiations with the Government relating to the transition to gas and renewables from coal-fired generation increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions, including interest rates and credit markets; 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, or wind required to operate our facilities; natural or man-made disasters; the threat of terrorism and cyberattacks; 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; our ability to fund our growth projects; our ability to maintain our credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes, including arbitrations under the PPAs; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays or changes in costs in the construction of the South Hedland power project; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our 2015 Annual MD&A and under the heading "Risk Factors" in our Annual Information Form for the year ended Dec. 31, 2015.

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 have been approved and 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. The purpose of the financial outlook contained herein is to provide readers with disclosure regarding our reasonable expectations as to the anticipated results of its proposed business activities for the periods indicated. Readers are cautioned that the financial outlook may not be appropriate for other reasons. We cannot assure that projected results or events, including our financial outlook, will be achieved.

Highlights

Consolidated Financial Highlights

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Revenues	**492**	438	**1,060**	1,031
Comparable EBITDA[1]	**248**	183	**527**	458
Net earnings (loss) attributable to common shareholders *(Restated* [2] *)*	**6**	(131)	**68**	(171)
Comparable net loss attributable to common shareholders[1]	**(20)**	(44)	**(6)**	(18)
Comparable FFO[1]	**175**	160	**372**	371
Cash flow from (used in) operating activities	**119**	(39)	**394**	114
Comparable FCF[1]	**62**	23	**149**	133
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Restated* [2] *)*	**0.02**	(0.47)	**0.24**	(0.62)
Comparable net loss per share[1]	**(0.07)**	(0.16)	**(0.02)**	(0.06)
Comparable FFO per share[1]	**0.61**	0.57	**1.29**	1.33
Comparable FCF per share[1]	**0.22**	0.08	**0.52**	0.48
Dividends declared per common share	**0.04**	0.18	**0.08**	0.36

As at	June 30, 2016	Dec. 31, 2015
Total assets	**10,544**	10,947
Total credit facilities, long-term debt, tax equity, and finance lease obligations[3], net of cash	**4,021**	4,441
Total long-term liabilities	**4,817**	5,704

- Comparable EBITDA for the three and six months ended June 30, 2016, increased by $65 million and $69 million to $248 million and $527 million, respectively, compared to the same periods in 2015. During the quarter, all segments delivered improved or similar results compared to last year, as was the case on a year-to-date basis except for U.S. Coal. Low prices in Alberta were largely mitigated through our hedging strategies, better availability, and cost reduction initiatives. Renewable assets acquired in the second half of 2015 contributed positively to our results in respect of both the three and six months ended June 30, 2016. Energy Marketing returned to a more normal performance after suffering a loss during the second quarter last year.
- Comparable FFO for the quarter increased by $15 million to $175 million compared to the same period in 2015. Last year, comparable EBITDA included higher unrealized mark-to-market losses from risk management activities in Energy Marketing which were excluded from comparable FFO.
- Comparable net loss attributable to common shareholders for the three months ended June 30, 2016 was $20 million ($0.07 net loss per share), up from a comparable net loss of $44 million ($0.16 net loss per share) during the three months ended June 30, 2015. The increase was a result of higher comparable EBITDA. Year-to-date, comparable net loss attributable to common shareholders was $6 million ($0.02 net loss per share), up from comparable net loss of $18 million ($0.06 net loss per share) in the same period in 2015. The improvement primarily related to higher comparable EBITDA, partially offset by higher depreciation as a result of asset acquisitions in 2015.

(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 Comparable FFO and Comparable FCF and Earnings and Other Measures on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(2) 2015 restated to reflect prior period correction to tax. Refer to the Accounting Changes section of this MD&A.
(3) Includes current portion.

- Reported net earnings attributable to common shareholders was $6 million ($0.02 net earnings per share) compared to a net loss of $131 million ($0.47 net loss per share) for the same period in 2015. On a year-to-date basis, reported net earnings attributable to common shareholders was $68 million ($0.24 net earnings per share) compared to a net loss of $171 million ($0.62 net loss per share) for the same period in 2015. Second quarter and year-to-date net loss in 2015 was impacted by a $40 million and $95 million income tax charge, respectively, associated with the sale of an economic interest in our Australian business to TransAlta Renewables and a $42 million ($28 million after-tax) and $73 million ($48 million after-tax) negative change, respectively, in the fair value of de-designated and economic hedges at U.S. Coal, compared to $13 million ($8 million after-tax) and $18 million ($12 million after-tax) this year. Second quarter and year-to-date reported earnings in 2016 include $12 million (2015 - $4 million loss) and $41 million (2015 - $4 million loss), respectively, of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests.
- The decrease in credit facilities, long-term debt, and finance lease obligations is primarily due to the repayment of our credit facilities with cash received from the sale to TransAlta Renewables of economic interests in certain Canadian assets completed in January. The strengthening of the Canadian dollar at the end of June also contributed to the reduction in balances from December.

Highlights

During the quarter, we continued to work on strengthening our financial condition and flexibility, improving our operating performance, and progressing our transition to clean power generation through the following initiatives:

- In August, we received commitments from our lenders to extend our syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018 respectively. All commitments are subject to finalizing loan documentation with key terms and covenants remaining unchanged. The extended facilities provide us financial flexibility to achieve our financial transition.
- On June 3, 2016, our indirect wholly-owned subsidiary New Richmond Wind L.P. issued non-recourse bonds in the amount of $159 million, bearing interest at 3.963 per cent, with principal and interest payable semi-annually, and maturing on June 30, 2032. Proceeds were used to repay our credit facility, repay a maturing Canadian Hydro Developers, Inc. ("CHD") bond, and further finance the construction of the South Hedland power project.
- We continued to advance the construction of the South Hedland power project. The bulk of the major equipment has arrived at site. Installation of the new fuel gas interconnection and high voltage works progressed with the connection and energization of the new generator transformer. We continue to expect the project to be delivered on schedule and on budget in mid-2017.

Earlier this year, we also completed the following transactions:

- In January, we completed the sale to TransAlta Renewables of an economic interest in the Sarnia cogeneration facility and two renewable energy facilities for proceeds valued at $540 million. Cash proceeds of this transaction were $173 million. We also received 15.6 million common shares of TransAlta Renewables and a $215 million convertible debenture.
- In March, our 12 million Series A Preferred Shares reached their first reset date. Approximately 10.2 million shares will now pay fixed dividends of nearly $0.68 per share annually (2.7 per cent) until their next reset date in 2021 (down from $1.15 per share prior to conversion) and approximately 1.8 million shares were converted into Series B Preferred Shares, which currently pay dividends of approximately $0.64225 per share (down from $1.15 per share) on an annualized basis (2.6 per cent), such rate being adjusted quarterly. Declaration of dividends remains subject to approval by the Board of Directors (the "Board").
- In January, we also announced we were reducing our dividend to $0.16 per common share on an annualized basis from $0.72 previously and suspended our dividend reinvestment and optional common share purchase plan. As a result, our annual dividend is approximately $46 million, down from $205 million, increasing our financial flexibility. Declaration of dividends is at the discretion of the Board.

In March and May, the buyers under the legislated Sundance, Sheerness, and Keephills PPAs announced their intention to transfer their respective obligations under the PPAs to the Balancing Pool as a result of a change in Alberta law. We do not expect this to impact our financial results. See the Significant and Subsequent events section of this MD&A.

Segmented Operational Results

Comparable EBITDA and operational performance for the business is as follows:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Availability (%)	**86.0**	81.0	**89.1**	85.4
Adjusted availability (%)(1)	**86.5**	80.9	**89.4**	86.1
Production (GWh)	**7,899**	8,820	**16,766**	18,720
Comparable EBITDA				
Canadian Coal	**93**	71	**196**	166
U.S. Coal(2)	**18**	10	**14**	32
Canadian Gas(2)	**56**	48	**121**	105
Australian Gas(2)	**33**	30	**64**	57
Wind and Solar	**36**	33	**97**	88
Hydro	**25**	25	**43**	39
Energy Marketing	**6**	(18)	**29**	5
Corporate	**(19)**	(16)	**(37)**	(34)
Total comparable EBITDA	**248**	183	**527**	458

- Canadian Coal: Comparable EBITDA during the second quarter and year-to-date improved by $22 million and $30 million, respectively, compared to the same periods in 2015. Cost reductions and effective hedging strategies have offset lower prices on uncontracted generation. During the second quarter, operational performance of the plants was also better than last year, with availability reaching almost 86 per cent compared to 75 per cent last year.
- U.S. Coal: Comparable EBITDA was up $8 million for the quarter, compared to the same period in 2015, but $18 million lower on a year-to-date basis compared to 2015. Market optimization resulted in stronger performance during the second quarter. The first half of 2015 benefited from higher price hedges entered into during a higher price environment in 2014.
- Canadian Gas: Comparable EBITDA for the three and six months ended June 30, 2016 was $56 million and $121 million compared to $48 million and $105 million, respectively, for the same periods in 2015, as result of a year over year change in mark-to-market on our gas position and lower operating costs from cost reduction initiatives.
- Australian Gas: Comparable EBITDA increased $3 million during the second quarter, and increased $7 million on a year-to-date basis compared to 2015. The increase to comparable EBITDA for the second quarter of 2016 was mainly due to the addition of capacity payments for the completed gas reticulation asset at our Solomon gas plant. Year-to-date we also benefited from increased comparable EBITDA from the natural gas pipeline commissioned in late March 2015.
- Wind and Solar: Comparable EBITDA is up $3 million during the quarter, and $9 million on a year-to-date basis, compared to the same periods in 2015, due to the contribution from assets with a combined capacity of 136 MW acquired during the second half of 2015. Lower prices in Alberta negatively impacted the revenue of our wind assets in Alberta. Higher generation partially offset the shortfall in Alberta prices.
- Hydro: Comparable EBITDA during the second quarter was similar to the same period in 2015. On a year-to-date basis, comparable EBITDA increased $4 million to $43 million, primarily due to a correction with a buyer of prior years' production volumes, and cost reduction initiatives.
- Energy Marketing: Comparable EBITDA increased by $24 million during the second quarter and on a year-to date basis due to a return to a normal level of gross margin from our short-term strategies. Last year's negative results and losses were largely attributable to volatile market conditions in the Alberta and Pacific Northwest regions.
- Corporate: Our Corporate overhead costs during the quarter and year-to-date were higher relative to 2015, as our cost reductions were offset by reduced allocations to our business segments.

(1) Adjusted for economic dispatching at U.S. Coal.

(2) See the Accounting Changes section of this MD&A for information on changes in the presentation of the Gas reportable segment.

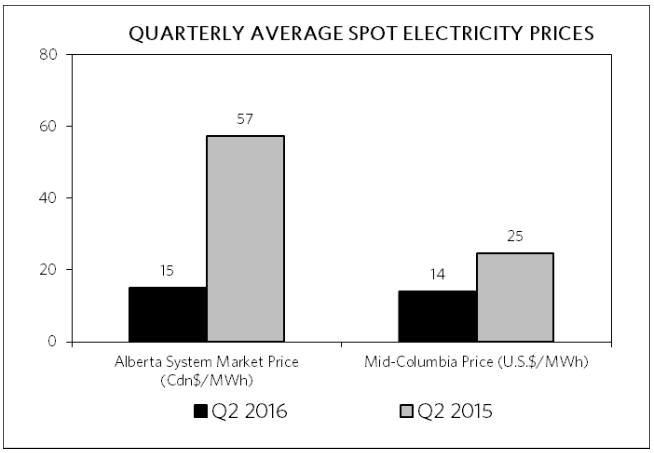
Availability and Production

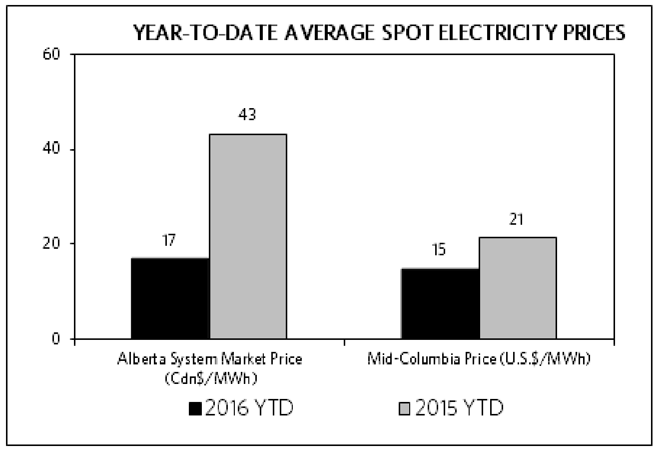
Availability for the three and six months ended June 30, 2016 improved over the same periods in 2015 primarily as a result of lower planned and unplanned outages at Canadian Coal.

Production for the three and six months ended June 30, 2016 decreased by 921 gigawatt hours ("GWh") and 1,954 GWh, respectively, compared to the same periods in 2015, primarily due to the restructuring of our contractual arrangement at Poplar Creek in the third quarter of 2015, and low prices in Ontario and the Pacific Northwest. Also, higher availability in Alberta Coal did not translate into a significant increase in power generation as some units were economically dispatched as a result of lower prices.

Electricity Prices

The average spot electricity prices for the three and six months ended June 30, 2016 decreased compared to the same periods in 2015 in both Alberta and the Pacific Northwest markets. Lower natural gas prices and seasonally low demand have muted volatility and depressed prices in both the Pacific Northwest and Alberta. We do not expect prices to increase significantly in Alberta during the balance of 2016 and expect Pacific Northwest prices to increase to seasonal norms.





Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO provides a proxy for the amount of cash generated from operating activities before changes in working capital, and provide the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FCF 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, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort comparable FFO and comparable FCF with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects. Comparable FFO per share and comparable FCF per share are calculated using the weighted average number of common shares outstanding during the period.

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Cash flow from (used in) operating activities	**119**	(39)	**394**	114
Change in non-cash operating working capital balances	**40**	198	**(54)**	247
Cash flow from operations before changes in working capital	**159**	159	**340**	361
Adjustments				
Decrease in finance lease receivable	**15**	1	**29**	2
Payment of restructuring costs	**-**	-	-	7
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	**-**	-	-	1
Other	**1**	-	**3**	-
Comparable FFO	**175**	160	**372**	371
Deduct:				
Sustaining capital	**(66)**	(104)	**(125)**	(174)
Dividends paid on preferred shares	**(10)**	(11)	**(22)**	(23)
Distributions paid to subsidiaries' non-controlling interests	**(37)**	(22)	**(76)**	(41)
Comparable FCF	**62**	23	**149**	133
Weighted average number of common shares outstanding in the period	**288**	279	**288**	278
Comparable FFO per share	**0.61**	0.57	**1.29**	1.33
Comparable FCF per share	**0.22**	0.08	**0.52**	0.48

Comparable FCF for the three and six months ended June 30, 2016 increased by $39 million and $16 million, respectively, compared to the same periods in 2015 as a result of lower sustaining capital spending, partially offset by higher distributions paid to non-controlling interests. Higher comparable FFO also contributed to the increase in the three month period. Higher distributions to non-controlling interests result from the additional shares issued to non-controlling interests by TransAlta in 2015 and 2016.

A reconciliation of comparable EBITDA to comparable FFO is as follows:

	3 months ended June 30		6 months ended June 30	
	2016	2015	2016	2015
Comparable EBITDA	248	183	527	458
Interest expense	(57)	(54)	(115)	(109)
Unrealized losses from risk management activities	9	31	2	36
Current income tax expense	(6)	(5)	(11)	(11)
Provisions	(8)	5	(7)	(4)
Decommissioning and restoration costs settled	(5)	(8)	(8)	(13)
Realized foreign exchange gain (loss)	-	5	(1)	13
Other non-cash items	(6)	3	(15)	1
Comparable FFO	175	160	372	371

For the second quarter of 2016, comparable FFO totaled $175 million, an increase of $15 million compared to the second quarter of 2015. Although comparable EBITDA was $65 million higher, prior period comparable EBITDA included higher unrealized mark-to-market losses from risk management activities which are excluded from comparable FFO.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined 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.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

As at	June 30, 2016[1]	Dec. 31, 2015
Comparable FFO	741	740
Add: Interest on debt net of capitalized interest	227	223
Comparable FFO before interest	968	963
Interest on debt	238	232
Add: 50 per cent of dividends paid on preferred shares	22	23
Adjusted interest	260	255
Comparable FFO before interest to adjusted interest coverage (times)	3.7	3.8

Our target for comparable FFO before interest to adjusted interest coverage is four to five times. The ratio was 3.7 for the last twelve months, a similar level compared to last year.

(1) Last 12 months. Our target range for comparable FFO in 2016 is $755 million to $835 million.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

As at	June 30, 2016	Dec. 31, 2015
Comparable FFO[1]	741	740
Less: 50 per cent of dividends paid on preferred shares[1]	(22)	(23)
Adjusted comparable FFO[1]	**719**	**717**
Period-end long-term debt[2]	4,114	4,495
Add: 50 per cent of issued preferred shares	471	471
Less: Cash and cash equivalents	(93)	(54)
Fair value asset of hedging instruments on debt[3]	(128)	(190)
Adjusted net debt	**4,364**	**4,722**
Adjusted comparable FFO to adjusted net debt (%)	**16.5**	**15.2**

Our comparable FFO to adjusted net debt ratio improved to 16.5 per cent, mostly due to the strengthening of the Canadian dollar in 2016 and debt reduction. Our target for adjusted comparable FFO to adjusted net debt is 20 to 25 per cent.

Adjusted Net Debt to Comparable EBITDA

As at	June 30, 2016	Dec. 31, 2015
Period-end long-term debt[2]	4,114	4,495
Less: Cash and cash equivalents	(93)	(54)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt[3]	(128)	(190)
Adjusted net debt	**4,364**	**4,722**
Comparable EBITDA[1]	**1,014**	**945**
Adjusted net debt to comparable EBITDA (times)	**4.3**	**5.0**

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. During the second quarter, our ratio improved compared to Dec. 31, 2015, mainly as a result of a lower debt balance due to the strengthening of the Canadian dollar and debt reduction.

(1) Last 12 months. Our target range for comparable FFO in 2016 is $755 million to $835 million.
(2) Includes finance lease obligations and tax equity financing.
(3) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at June 30, 2016 and Dec. 31, 2015.

Significant and Subsequent Events

$159 Million Project Financing

On June 3, 2016, TransAlta Renewables' indirect wholly-owned subsidiary, New Richmond Wind L.P. (the "Issuer"), closed a bond offering of approximately $159 million which is secured by a first ranking charge over all assets of the Issuer. The bonds are amortizing and bear interest from their date of issue at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032. Net proceeds of the financing were used to reduce drawdowns on our credit facility during the second quarter, repay the CHD bond, and fund the construction of the South Hedland power project.

Sundance, Sheerness, and Keephills PPA Terminations

In March and May 2016, the buyers under the legislated Sundance, Sheerness, and Keephills PPAs announced their intention to transfer their respective obligations under the PPAs to the Balancing Pool as a result of a change in Alberta law. The Balancing Pool is presently investigating whether these transfers are permitted by the terms of the PPAs in the current circumstances and, if so, when the transfers would become effective. The outcome remains uncertain. If the Balancing Pool confirms the transfers, it will assume the role of the buyers and carry out the responsibilities of the buyers under the PPAs, including dispatching the generating units and making the capacity and energy payments to TransAlta until the end of the PPA terms. Pursuant to the *Electric Utilities Act* (Alberta), it could also choose to terminate the PPAs after following the requirements of legislation, which would include paying TransAlta an amount equal to the applicable closing net book value of the generating units. TransAlta does not presently expect the transfer of the PPAs to the Balancing Pool to have a material impact on our business.

On July 25, 2016, the Attorney General for the Province of Alberta filed a claim against all buyers who have purported to transfer their respective obligations under the PPAs, the owner of the Battle River #5 PPA, the Alberta Utilities Commission, and Balancing Pool, challenging the basis on which the buyers have purported to transfer their PPA obligations to the Balancing Pool. The outcome of this claim is uncertain.

Notwithstanding the above, TransAlta continues to operate the PPA generating units in their ordinary course and receive the capacity and energy payments due to it under the PPAs.

Credit Facility Renewal

In August, we received commitments from our lenders to extend our syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018 respectively. All commitments are subject to finalizing loan documentation with key terms and covenants remaining unchanged. The extended facilities provide us financial flexibility to achieve our financial transition.

Credit Ratings Outlook

As at June 30, 2016, we maintain investment grade ratings from three credit rating agencies, but during the first quarter, DBRS and Fitch changed their outlooks from stable to negative. Their negative outlooks are a reflection of low energy prices and concerns over coal generation transition in Alberta. We remain focused on strengthening our financial position by de-leveraging our capital structure and securing a fair agreement with the Government of Alberta that assists them in their goal to transition the generation in the province to gas and renewables.

Conversion of Series A Preferred Shares to Series B Preferred Shares

On March 17, 2016, 1,824,620 of our 12 million Series A Cumulative Redeemable Fixed Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares. For the next five years, the Series A Shares will pay a fixed cumulative preferential cash dividend of $0.67725 per share annually (down from $1.15 per share), subject to the Board's dividend declaration. The Series B Shares will pay quarterly floating rate cumulative preferential cash dividends set at the sum of the 90 day Government of Canada Treasury Bill rate plus 2.03 per cent. The annualized quarterly dividend rate for the Series B Shares for the 3-month floating rate period for the second quarter 2016 is $0.623 per share.

South Hedland

We continued to advance the construction of the South Hedland power project. The bulk of the major equipment has arrived at site. Installation of the new fuel gas interconnection and high voltage works progressed with the connection and energization of the new generator transformer. We continue to expect the project to be delivered on schedule and on budget in mid-2017.

Environmental Regulation Updates

Refer to the Environmental and Local Communities Capital section of our 2015 Annual MD&A for further details that supplement the recent developments as discussed below.

Alberta

On Nov. 22, 2015, the Government of Alberta announced through the Climate Leadership Plan its intent, among other things, to phase out emissions from coal-fired generation by 2030, replace two-thirds of the retiring coal-fired generation with renewable generation, and impose a new carbon price of $30 per tonne of CO_2 emissions based on an industry-wide performance standard. On March 16, 2016, the Government of Alberta announced the appointment of a Coal Phase-out Facilitator to work with coal-fired electricity generators, the Alberta Electric System Operator, and the Government of Alberta to develop options to phase out emissions from coal-fired generation by 2030. The Coal Phase-out Facilitator is tasked with presenting options to the government that will strive to maintain the reliability of Alberta's electricity grid, maintain stability of prices for consumers, and avoid unnecessarily stranding capital. Discussions with the coal-fired generators, including TransAlta, are now in progress.

On May 24, 2016 Alberta passed the *Climate Leadership Implementation Act* which establishes the carbon tax framework for its application to fuels. It is expected that additional regulations will be developed in later 2016 governing the treatment of large industrial emitters. The Climate Leadership Plan will be implemented for the electricity sector on January 1, 2018.

In March 2016, Alberta began development of its renewable energy procurement process design for the Alberta Electric System Operator to procure a first block of renewable generation projects to be in-service by mid-2019. A decision on the final design parameters is expected by the end of 2016.

Ontario

On Feb. 25, 2016, Ontario released draft regulations for its greenhouse gas cap and trade program which was finalized on May 19, 2016. The regulations are to become effective Jan. 1, 2017, and will apply to all fossil fuel 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 power purchase agreements. Further details of the regulations are being developed with public consultation, in which we are participating.

U.S. Federal and Pacific Northwest

On Feb. 9, 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending consideration as to whether the regulations are lawful. It is not clear yet how this may affect the future of the Clean Power Plan. As a result of our 2011 agreement for coal transition with the State of Washington, we do not expect the proposed regulations to significantly affect our U.S. operations.

Discussion of Segmented Comparable Results

In January 2016, we began reporting Canadian Gas and Australian Gas as separate business segments. Previously these segments were reported as one business segment, Gas. The segment has now been differentiated geographically to provide additional information to our readers. See the Current Accounting Changes section of this MD&A for additional information.

Comparable figures are not defined under IFRS. Refer to the Earnings and Other Measures on a Comparable Basis section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Canadian Coal

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Availability (%)	**85.7**	74.6	**86.1**	79.5
Contract production (GWh)	**4,335**	4,265	**9,254**	9,181
Merchant production (GWh)	**986**	958	**1,895**	1,979
Total production (GWh)	**5,321**	5,223	**11,149**	11,160
Gross installed capacity (MW)	**3,791**	3,771	**3,791**	3,771
Revenues	**229**	205	**463**	451
Fuel and purchased power	**90**	83	**173**	182
Comparable gross margin	**139**	122	**290**	269
Operations, maintenance, and administration	**43**	48	**88**	97
Taxes, other than income taxes	**3**	3	**6**	6
Comparable EBITDA	**93**	71	**196**	166
Depreciation and amortization	**79**	75	**155**	146
Comparable operating income	**14**	(4)	**41**	20
Sustaining capital:				
Routine capital	**11**	15	**13**	23
Mine capital	**7**	8	**7**	12
Finance leases	**3**	3	**6**	6
Planned major maintenance	**13**	47	**50**	77
Total sustaining capital expenditures	**34**	73	**76**	118

Production for the three months ended June 30, 2016 increased 98 GWh compared to the same period in 2015, primarily due to lower derates and lower planned and unplanned outages, partially offset by higher paid curtailments and economic dispatching as a result of lower prices in Alberta. Production for the six months ended June 30, 2016 was in line with the same period in 2015.

Comparable EBITDA for the three and six months ended June 30, 2016 was up $22 million and $30 million, respectively, compared to the same periods in 2015, primarily due to better availability and lower operations, maintenance, and administration costs. Our hedging strategy mostly mitigated the impact of low power prices on uncontracted generation. On a year-to-date basis comparable EBITDA also benefited from lower gas consumption and cost of coal from the first quarter of 2016.

Depreciation and amortization for the three and six months ended June 30, 2016 increased $4 million and $9 million, respectively, compared to the same periods in 2015, mainly due to higher asset retirements and timing of capital expenditures.

Sustaining capital expenditures for the three and six months ended June 30, 2016 were lower by $39 million and $42 million, respectively, compared to the same periods in 2015 as there were no major overhauls initiated during the second quarter of 2016 with only a portion carried over from the first quarter.

U.S. Coal

	3 months ended June 30		6 months ended June 30	
	2016	2015[2]	**2016**	2015[2]
Availability (%)	**68.8**	70.4	**84.4**	80.7
Adjusted availability (%)[1]	**72.1**	69.8	**86.1**	84.8
Contract sales volume (GWh)	**916**	696	**1,831**	1,385
Merchant sales volume (GWh)	**186**	759	**588**	1,336
Purchased power (GWh)	**(923)**	(738)	**(1,868)**	(1,449)
Total production (GWh)	**179**	717	**551**	1,272
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**54**	65	**115**	147
Fuel and purchased power	**23**	44	**75**	91
Comparable gross margin	**31**	21	**40**	56
Operations, maintenance, and administration	**12**	10	**24**	22
Taxes, other than income taxes	**1**	1	**2**	2
Comparable EBITDA	**18**	10	**14**	32
Depreciation and amortization	**27**	17	**24**	32
Comparable operating loss	**(9)**	(7)	**(10)**	-
Sustaining capital:				
Routine capital	**1**	1	**2**	1
Finance leases	**2**	1	**2**	1
Planned major maintenance	**8**	6	**11**	9
Total	**11**	8	**15**	11

For the three and six months ended June 30, 2016, production decreased 538 GWh and 721 GWh, respectively, compared to the same periods in 2015, due mainly to increased economic dispatching. Lower prices during the first and second quarters of 2016 provided us the opportunity to shut down our generation earlier and supply our contractual obligation by buying cheaper power in the market. We used that time to execute planned major maintenance on both units.

Comparable EBITDA improved by $8 million for the second quarter of 2016 compared to the same period in 2015 as a result of the favorable impact of economic dispatching which benefited from lower prices for purchased power and higher volumes of contracted production compared to the prior year. We also benefited from the favorable impacts of foreign exchange and mark-to-market on certain forward financial contracts that do not qualify for hedge accounting. These improvements were partially offset by reversals of coal inventory impairments from previous quarters and the consumption of previously impaired coal in 2015.

Comparable EBITDA decreased by $18 million for the first six months of 2016 compared to the same period in 2015 as a result of the unfavorable impacts from economic dispatching in the first quarter of 2016 due to lower realized prices on contracted production, unfavorable impacts of mark-to-market on certain forward financial contracts that do not qualify for hedge accounting, higher consumption of previously impaired coal in 2015, and unfavorable impacts of foreign exchange.

Depreciation and amortization for the second quarter of 2016 was higher by $10 million due to lower discount rates being applied to our decommissioning obligation for the Centralia mine, as opposed to in the first quarter of 2016, where higher discount rates triggered a recovery. As the mine is in the reclamation stage, the adjustment flows directly to earnings.

(1) Adjusted for economic dispatching.
(2) Restated to include non-operating legacy U.S. Gas costs. Refer to the Accounting Changes section of this MD&A.

Canadian Gas

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Availability (%)	**95.5**	94.1	**97.5**	96.9
Contract production (GWh)	**712**	1,022	**1,455**	2,049
Merchant production (GWh)	**66**	360	**66**	1,054
Total production (GWh)	**778**	1,382	**1,521**	3,103
Gross installed capacity (MW)(1)	**1,057**	1,183	**1,057**	1,183
Revenues	**105**	113	**227**	256
Fuel and purchased power	**35**	47	**77**	114
Comparable gross margin	**70**	66	**150**	142
Operations, maintenance, and administration	**14**	17	**28**	35
Taxes, other than income taxes	**-**	1	**1**	2
Comparable EBITDA	**56**	48	**121**	105
Depreciation and amortization	**27**	22	**55**	46
Comparable operating income	**29**	26	**66**	59
Sustaining capital:				
Routine capital	**2**	1	**2**	3
Planned major maintenance	**-**	5	**2**	12
Total	**2**	6	**4**	15

Production for the three and six months ended June 30, 2016 decreased 604 GWh and 1,582 GWh, respectively, primarily due to the restructuring of our contract with Suncor at Poplar Creek in the third quarter of 2015 and unfavorable market conditions in Ontario.

Comparable EBITDA for the three and six months ended June 30, 2016 increased by $8 million and $16 million, respectively, compared to the same period in 2015, as result of a year over year change in mark-to-market on our gas position of $2 million and $10 million, respectively, and lower operating costs from cost reduction initiatives.

Depreciation and amortization for the three and six months ended June 30, 2016 increased $5 million and $9 million, respectively, compared to the same periods in 2015 due mainly to the Poplar Creek contract restructuring, which resulted in the derecognition of Poplar Creek from property, plant, and equipment and the recognition of a finance lease receivable. We record the decrease 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 from the plant.

Sustaining capital for the three and six months ended June 30, 2016, decreased $4 million and $11 million, respectively, compared to the same periods in 2015, primarily as a result of the refurbishment of a spare engine during the first quarter of 2015. Also, the obligation to maintain the Poplar Creek facility has been transferred to our customer as part of our new contract arrangement.

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor. We continue to own a portion of the facility and have included our portion as a part of gross capacity measures. Poplar Creek has been removed from our availability and production metrics, effective Sept. 1, 2015.

Australian Gas

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Availability (%)	**94.3**	92.6	**92.2**	90.6
Contract production (GWh)	**371**	354	**743**	657
Gross installed capacity (MW)(1)	**425**	348	**425**	348
Revenues	**45**	41	**87**	79
Fuel and purchased power	**6**	5	**11**	10
Comparable gross margin	**39**	36	**76**	69
Operations, maintenance, and administration	**6**	6	**12**	12
Comparable EBITDA	**33**	30	**64**	57
Depreciation and amortization	**3**	5	**8**	9
Comparable operating income	**30**	25	**56**	48

Sustaining capital:				
Routine capital	**-**	1	**1**	1
Planned major maintenance	**5**	-	**5**	-
Total	**5**	1	**6**	1

Production for the three months ended June 30, 2016 increased 17 GWh compared to the same period in 2015 due to higher customer demand. The production increase on a year-to-date basis of 86 GWh compared to 2015 related mostly to a change in the power import regime at one of our customer's locations. Due to the nature of our contract, the change did not have a significant financial impact.

Comparable EBITDA increased by $3 million during the second quarter of 2016 to $33 million compared to the same period in 2015, mainly due to the addition of capacity payments for the gas reticulation asset at our Solomon gas plant that was completed in May. On a year-to-date basis, we also benefited from increased comparable EBITDA from the natural gas pipeline that was commissioned in late March 2015.

Sustaining capital for the three and six months ended June 30, 2016 increased by $4 million and $5 million, respectively, compared to the same periods in 2015 as a result of timing of planned major maintenance.

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

Wind and Solar

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Availability (%)	**95.0**	95.2	**95.9**	95.1
Contract production (GWh)	**486**	451	**1,197**	1,088
Merchant production (GWh)	**245**	157	**665**	497
Total production (GWh)	**731**	608	**1,862**	1,585
Gross installed capacity (MW)(1)	**1,408**	1,289	**1,408**	1,289
Revenues	**55**	49	**139**	122
Fuel and purchased power	**3**	2	**12**	6
Comparable gross margin	**52**	47	**127**	116
Operations, maintenance, and administration	**14**	12	**26**	24
Taxes, other than income taxes	**2**	2	**4**	4
Comparable EBITDA	**36**	33	**97**	88
Depreciation and amortization	**29**	22	**59**	44
Comparable operating income	**7**	11	**38**	44
Sustaining capital:				
Routine capital	**1**	-	**1**	-
Planned major maintenance	**4**	4	**6**	6
Total	**5**	4	**7**	6

Production for the three and six months ended June 30, 2016, increased by 123 GWh and 277 GWh compared to the same periods in 2015, mainly due to the contribution from assets acquired during the second half of 2015 and higher wind volumes across our Western Canada and US wind fleet, partially offset by lower wind resources in Eastern Canada.

Comparable EBITDA for the three and six months ended June 30, 2016 increased $3 million and $9 million respectively, compared to the same periods in 2015, mainly due to the contribution of $7 million and $13 million, respectively, from assets acquired in 2015. Higher generation from our portfolio partially reduced the impact of lower merchant prices in Alberta for the second quarter and year-to-date periods, respectively.

Depreciation and amortization increased by $7 million and $15 million for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, primarily due to the addition of assets acquired during the second half of 2015.

(1) *Our 2015 capacity excludes acquisitions completed during the second half of 2015.*

Hydro

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Contract production (GWh)	**482**	507	**899**	905
Merchant production (GWh)	**37**	29	**41**	38
Total production (GWh)	**519**	536	**940**	943
Gross installed capacity (MW)	**926**	913	**926**	913
Revenues	**38**	38	**66**	63
Fuel and purchased power	**2**	3	**4**	4
Comparable gross margin	**36**	35	**62**	59
Operations, maintenance, and administration	**10**	9	**17**	19
Taxes, other than income taxes	**1**	1	**2**	1
Comparable EBITDA	**25**	25	**43**	39
Depreciation and amortization	**6**	6	**13**	12
Comparable operating income	**19**	19	**30**	27
Sustaining capital:				
Routine capital, excluding hydro life extension	**2**	-	**2**	-
Hydro life extension	**3**	5	**6**	11
Planned major maintenance	**-**	2	**2**	3
Total	**5**	7	**10**	14

Production for the three and six months ended June 30, 2016 decreased by 17 GWh and 3 GWh compared to the same periods in 2015, primarily due to changes in our reservoir levels to accommodate scheduled maintenance outages.

Comparable EBITDA during the second quarter of 2016 remained consistent with 2015. The first half of 2016 benefited from cost reduction initiatives achieved during the first quarter of 2016.

Energy Marketing

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Revenues and comparable gross margin	**11**	(17)	**43**	14
Operations, maintenance, and administration	**5**	1	**14**	9
Comparable EBITDA	**6**	(18)	**29**	5
Depreciation and amortization	**-**	-	**1**	-
Comparable operating income	**6**	(18)	**28**	5

For the three and six months ended June 30, 2016, comparable EBITDA increased $24 million compared to the same periods in 2015 due to a return to normal level of gross margin from our short-term strategies and solid performance in our natural gas and Alberta trading portfolios. During the second quarter of 2015, unexpectedly volatile markets in Alberta and the Pacific Northwest negatively impacted gross margin.

Corporate

The expenses incurred by the Corporate Segment are as follows:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Operations, maintenance, and administration and taxes other than income taxes	**19**	16	**37**	34
Depreciation and amortization	**6**	7	**13**	13
Comparable operating loss	**25**	23	**50**	47
Sustaining capital:				
Routine capital	**4**	5	**7**	9

Our Corporate overhead costs increased by $3 million during the three and six months ended June 30, 2016 compared to the same periods in 2015 due to a change in allocation methodologies with business units.

Other Consolidated Analysis

Income Taxes

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Earnings (loss) before income taxes	**(4)**	(73)	**49**	(44)
Comparable adjustments:				
Impacts associated with certain de-designated and economic hedges	**13**	42	**18**	73
Economic hedges of non-controlling interest in intercompany foreign exchange contracts	**(2)**	1	**(4)**	1
Asset impairment charges (reversals)	**-**	(1)	**-**	(1)
Restructuring expense	**-**	-	**-**	7
Flood-related maintenance costs, net of insurance recovery	**-**	-	**-**	1
Comparable earnings (loss) before tax	**7**	(31)	**63**	37
Comparable earnings attributable to non-controlling interests before tax	**(18)**	(18)	**(45)**	(34)
Comparable earnings (loss) attributable to TransAlta shareholders subject to tax	**(11)**	(49)	**18**	3
Income tax expense (recovery) *(Restated* [1] *)*	**(24)**	35	**(42)**	78
Comparable income tax expense adjustments:				
Income tax recovery related to impacts associated with certain de-designated and economic hedges	**5**	14	**6**	25
Income tax recovery related to restructuring provision	**-**	-	**-**	2
Income tax (expense) recovery related to (writedown) reversal of a writedown of deferred income tax assets	**23**	(3)	**46**	12
Income tax expense related to investment in subsidiary *(Restated* [1] *)*	**(3)**	(40)	**(3)**	(95)
Income tax expense related to changes in corporate income tax rates	**-**	(20)	**(1)**	(20)
Income tax expense related to non-comparable items attributable to economic hedges of non-controlling interest in intercompany foreign exchange contracts	**-**	-	**(1)**	-
Comparable income tax expense (recovery)	**1**	(14)	**5**	2
Comparable income tax expense attributable to non-controlling interests	**(2)**	(2)	**(3)**	(4)
Comparable income tax expense (recovery) attributable to TransAlta shareholders	**(1)**	(16)	**2**	(2)
Comparable effective tax rate on earnings attributable to TransAlta shareholders (%)	**9**	33	**11**	67

(1) 2015 restated to reflect prior period correction. Refer to the Accounting Changes section of this MD&A.

The comparable income tax expense attributable to TransAlta shareholders for the three and six months ended June 30, 2016 increased compared to the same periods in 2015, primarily due to higher comparable earnings.

The comparable effective tax rate on earnings attributable to TransAlta shareholders decreased for the three and six months ended June 30, 2016, compared to the same period in 2015, primarily due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which the pre-tax income was earned.

As disclosed in previous periods, we had written certain deferred tax assets off as it was no longer considered probable that sufficient future taxable income would be available to utilize the underlying tax losses. In the second quarter of 2016, our views on the ability to utilize the underlying tax losses improved based on unrealized gains on investments and hedging instruments, such that a reversal of the previous writedowns were warranted. As a result, for the three months ended June 30, 2016 we recorded a recovery of $23 million (June 30, 2015 - $3 million writedown) and for the six months ended June 30, 2016, we recorded a recovery of $46 million (June 30, 2015 - $12 million).

In order to give effect to the sale of an economic interest in the Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a $40 million and $95 million deferred tax liability on TransAlta's investment in a subsidiary for the three and six months ended June 30, 2015, respectively. The deferred tax liability had not been recognized previously, since prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

Capital Structure and Liquidity

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

	June 30, 2016		Dec. 31, 2015	
As at	$	%	$	%
Recourse debt - CAD debentures	1,045	12	1,044	12
Recourse debt - U.S. senior notes	2,077	25	2,221	26
Credit facilities	-	-	315	4
U.S. tax equity financing	43	1	50	1
Other	16	-	17	-
Less: cash and cash equivalents	(93)	(1)	(54)	(1)
Less: fair value asset of hedging instruments on debt	(128)	(2)	(190)	(2)
Net recourse debt	2,960	35	3,403	40
Non-recourse debt	857	10	766	9
Finance lease obligations	76	1	82	1
Total net debt	3,893	46	4,251	50
Non-controlling interests	1,125	13	1,029	12
Equity attributable to shareholders				
Common shares	3,093	37	3,075	35
Preferred shares	942	11	942	11
Contributed surplus, deficit, and accumulated other comprehensive income	(610)	(7)	(656)	(8)
Total capital	8,443	100	8,641	100

During the second quarter:

- New Richmond Wind L.P., our indirect subsidiary, issued a non-recourse bond in the amount of $159 million; and
- CHD, an indirect subsidiary, repaid a $27 million 5.69 per cent non-recourse debenture at maturity, and early redeemed $10 million of non-recourse bonds, maturing in 2018 with coupon rates of 5.77 per cent and 7.03 per cent.

During the first quarter, we paid out the credit facilities balance of approximately $315 million through a combination of cash flows from operations and cash proceeds of $173 million received from the sale to TransAlta Renewables of an economic interest in the 506 MW Sarnia cogeneration facility and two renewable energy facilities.

The weakening of the US dollar decreased our long-term debt balances by $151 million since Dec. 31, 2015. Almost all of our U.S.-denominated debt is hedged 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:

6 months ended June 30	2016
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	(79)
Foreign currency cash flow hedges on debt	(66)
Economic hedges and other	(6)
Total	(151)

During the period through Dec. 31, 2018, we have approximately $1.5 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising debt secured by certain contracted assets in Canada and the U.S. and using cash generated by our business. In January, we announced our decision to reduce our dividend to increase our financial flexibility.

Credit Facilities

Our credit facilities provide us with significant liquidity. At June 30, 2016, we had a total of $2.1 billion (Dec. 31, 2015 - $2.2 billion) of committed credit facilities, of which $1.5 billion (Dec. 31, 2015 - $1.3 billion) was available. We are in compliance with the terms of the credit facilities. At June 30, 2016, the $0.6 billion (Dec. 31, 2015 - $0.9 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2015 - $0.3 billion) and letters of credit of $0.6 billion (Dec. 31, 2015 - $0.6 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility expiring in 2019, and four bilateral credit facilities expiring in 2017. In August 2016, we received commitments from our lenders to extend our syndicated credit facility and three bilateral credit facilities by one year.

Share Capital

On March 17, 2016, we announced that 1,824,620 of our 12 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares. Refer to the Highlights and Significant and Subsequent Events sections of this MD&A for further details.

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

As at	Aug. 8, 2016	June 30, 2016	Dec. 31, 2015
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	284.0
Preferred shares			
Series A	10.2	10.2	12.0
Series B	1.8	1.8	-
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests

As of June 30, 2016, we own 64.0 per cent (Dec. 31, 2015 – 66.6 per cent) of TransAlta Renewables. On Jan. 6, 2016, we completed the sale of an economic interest based on the cash flows of the 506 MW Sarnia cogeneration facility and two renewable energy facilities with total capacity of 105 MW to TransAlta Renewables for $540 million.

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.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Interest on debt	**58**	56	**118**	113
Capitalized interest	**(4)**	(2)	**(7)**	(5)
Loss on redemption of bonds	**1**	-	**1**	-
Interest on finance lease obligations	**1**	-	**2**	1
Other	**1**	-	**1**	-
Accretion of provisions	**5**	5	**11**	10
Net interest expense	**62**	59	**126**	119

For the three and six months ended June 30, 2016, net interest expense increased compared to the same periods in 2015, primarily due to higher interest expense on foreign-denominated debt due to the stronger US dollar relative to the same periods last year, a slight increase in the cost of our bank facilities due to the Moody's Investor Services downgrade that occurred in the fourth quarter of 2015, as well as higher amounts of letters of credits outstanding during the periods, partially offset by higher capitalized interest.

Dividends to Shareholders

On Jan. 14, 2016, we announced a reduction of our common share dividend from $0.72 annually to $0.16 annually and the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan. These actions were taken as part of a plan to maximize our long-term financial flexibility. The declaration of dividends is at the discretion of the Board.

On July 19, 2016, we declared a quarterly dividend of $0.04 per share on common shares, payable on Oct. 1, 2016 and a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.16144 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on Sept. 30, 2016.

On April 21, 2016, we declared a quarterly dividend of $0.04 per share on common shares, payable on July 1, 2016, and a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.15490 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on June 30, 2016.

Non-Controlling Interests

Comparable earnings attributable to non-controlling interests for the three months ended June 30, 2016 was consistent with the same period in 2015. Despite higher non-controlling interest ownership of TransAlta Renewables relative to the prior period, higher foreign exchange losses offset higher operating income. On a year-to-date basis, comparable earnings attributable to non-controlling interests increased by $12 million to $42 million, primarily due to the Australian and Canadian portfolio dropdowns contributing to higher earnings in TransAlta Renewables, partially offset by unrealized foreign exchange losses on some of the financial interests in the Australian Assets.

Financial Position

The following charts highlight significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2015 to June 30, 2016:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	39	Timing of receipts and payments, repayment of credit facilities and long-term debt, and bond offering
Trade and other receivables	(115)	Timing of customer receipts and seasonality of revenue
Prepaid expenses	20	Prepayment of property taxes
Inventory	19	Increase in coal inventory following lower production in the US, partially offset by the use of emissions inventory
Finance lease receivables (long-term)	(42)	Unfavourable changes in foreign exchange rates ($25 million) and scheduled receipts from our Poplar Creek restructuring ($25 million), partially offset by an increased balance due to completion of gas reticulation work at the Solomon Power station ($14 million)
Property, plant, and equipment, net	(225)	Depreciation for the period ($274 million), unfavourable changes in foreign exchange rates ($77 million), and revisions to decommissioning and restoration costs ($13 million), partially offset by additions ($163 million)
Intangible assets	(11)	Amortization ($19 million) and unfavourable changes in foreign exchange rates ($2 million), partially offset by additions ($11 million)
Risk management assets (current and long-term)	(95)	Unfavourable changes in foreign exchange rates and contract settlements, partially offset by favourable market price movements.
Other	7	
Total decrease in assets	**(403)**	

	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(35)	Timing of payments and accruals
Dividends payable	(37)	Reduction of quarterly dividend
Credit facilities, long-term debt, and finance lease obligations (including current portion)	(381)	Credit facility repayment ($315 million), repayment of long-term debt ($64 million), and favourable effects of changes in foreign exchange rates ($151 million), partially offset by a bond issuance ($159 million)
Decommissioning and other provisions (current and long-term)	(32)	Increase in risk-adjusted discount rates
Defined benefit obligation and other long-term liabilities	48	Decrease in risk free discount rates and actuarial losses
Risk management liabilities (current and long-term)	(129)	Favourable market price movements and contract settlements, partially offset with favourable market price movements
Equity attributable to shareholders	64	Net earnings ($91 million), issuance of common shares ($18 million), gains on cash flow hedges ($103 million), partially offset by net losses on translating net assets of foreign operations ($67 million), actuarial losses on defined benefit plans ($36 million), and common and preferred share dividends ($45 million)
Non-controlling interests	96	Sale of economic interests to TransAlta Renewables, partially offset by distributions paid and payable to non-controlling interests
Other	3	
Total decrease in liabilities and equity	**(403)**	

Cash Flows

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three and six months ended June 30, 2016 compared to the same periods in 2015:

3 months ended June 30	2016	2015	Primary factors explaining change
Cash and cash equivalents, beginning of period	30	61	
Provided by (used in):			
Operating activities	119	(39)	Favourable change in non-cash working capital of $158 million
Investing activities	(76)	(116)	Lower additions to property, plant, and equipment ($47 million) and a higher decrease in finance lease receivables ($14 million), partially offset by unfavourable change in non-cash working capital ($25 million)
Financing activities	20	165	Decreased borrowings under credit facilities ($22 million), higher repayments of long-term debt ($73 million), and a decrease in proceeds on sale of non-controlling interest in a subsidiary ($211 million), partially offset by the issuance of a bond ($159 million)
Cash and cash equivalents, end of period	93	71	

6 months ended June 30	2016	2015	Primary factors explaining change
Cash and cash equivalents, beginning of year	54	43	
Provided by (used in):			
Operating activities	394	114	Favourable change in non-cash working capital ($301 million), partially offset by a decrease in cash earnings ($21 million)
Investing activities	(143)	(259)	Lower additions to property, plant, and equipment ($86 million) and a higher decrease in finance lease receivables ($27 million), partially offset by an unfavourable change in non-cash investing working capital ($16 million)
Financing activities	(210)	172	An increase in repayments of borrowings under credit facilities ($920 million), higher distributions paid to subsidiaries' non-controlling interest ($35 million), decrease in proceeds on sale of non-controlling interest in subsidiary ($49 million), and lower realized gains on financial instruments ($77 million), partially offset by lower repayment of long-term debt ($570 million) and issuance of non-recourse bond ($159 million)
Translation of foreign currency cash	(2)	1	
Cash and cash equivalents, end of period	93	71	

Unconsolidated Structured Entities or Arrangements

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

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At June 30, 2016, we provided letters of credit totalling $607 million (Dec. 31, 2015 - $575 million) and cash collateral of $82 million (Dec. 31, 2015 - $74 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Commitments

On July 5, 2016, we renewed one ten-year and two five-year long-term service agreements with three of our wind facilities to provide on-going maintenance. Total committed expenditures under the agreements are approximately $30 million.

Earnings and Other Measures on a Comparable Basis

We evaluate our performance and the performance of our business segments using a variety of measures. Those measures discussed below, and certain other measures referenced elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Each business segment assumes responsibility for its operating results measured by gross margin and operating income. Operating income and gross margin provides management and investors with a measurement of operating performance that is readily comparable from period to period.

In calculating these items, we exclude certain items as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

During 2016, prior period restatements were made to the 2015 period. Refer to the Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable EBITDA and comparable earnings for the three and six months ended June 30, 2016 and the same period in 2015 are as follows. References are to the reconciliation presented on the following pages.

			3 months ended June 30		6 months ended June 30	
			2016	2015	**2016**	2015
Reference number	Adjustment	Segment				
Reclassifications:						
1	Finance lease income used as a proxy for operating revenue	Australian Gas	**13**	11	**26**	23
		Canadian Gas	**4**	2	**7**	3
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	**13**	1	**27**	2
		Australian Gas	**2**	-	**2**	-
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	**15**	16	**30**	30
Adjustments (increasing (decreasing) earnings to arrive at comparable results):						
4	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	**13**	42	**18**	73
5	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	**-**	-	**-**	1
6	Asset impairment reversals	U.S. Coal	**-**	(1)	**-**	(1)
7	Restructuring expense	Canadian Coal	**-**	-	**-**	7
8	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	**(2)**	1	**(4)**	1
9	Net tax effect on comparable adjustments subject to tax	Unassigned	**(5)**	(14)	**(5)**	(27)
10	Deferred income tax rate adjustment	Unassigned	**-**	20	**1**	20
11	Reversal (accrual) of a writedown of deferred income tax assets	Unassigned	**(23)**	3	**(46)**	(12)
12	Income tax expense related to temporary difference on investment in subsidiary *(Restated)**	Unassigned	**3**	40	**3**	95
13	Non-comparable items attributable to non-controlling interests	Unassigned	**(12)**	(4)	**(41)**	(4)

** 2015 restated to reflect prior period correction. Refer to the Accounting Changes section of this MD&A.*

A reconciliation of comparable results to reported results for the three and six months ended June 30, 2016 and the same periods in 2015 is as follows:

	3 months ended June 30, 2016				3 months ended June 30, 2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	492	32 [1, 2]	13 [4]	537	438	14 [1, 2]	42 [4]	494
Fuel and purchased power	174	(15) [3]	-	159	200	(16) [3]	-	184
Gross margin	318	47	13	378	238	30	42	310
Operations, maintenance, and administration	122	-	-	122	119	-	-	119
Asset impairment reversals	-	-	-	-	(1)	-	1 [6]	-
Taxes, other than income taxes	8	-	-	8	8	-	-	8
EBITDA	188	47	13	248	112	30	41	183
Depreciation and amortization	147	30 [2, 3]	-	177	137	17 [2, 3]	-	154
Operating income (loss)	41	17	13	71	(25)	13	41	29
Finance lease income	17	(17) [1]	-	-	13	(13) [1]	-	-
Foreign exchange gain (loss)	-	-	(2) [8]	(2)	(2)	-	1 [8]	(1)
Earnings before interest and taxes	58	-	11	69	(14)	-	42	28
Net interest expense	62	-	-	62	59	-	-	59
Income tax expense (recovery)	(24)	-	25 [9, 11]	1	35	-	(49) [9, 10, 11, 12]	(14)
Net earnings (loss)	20	-	(14)	6	(108)	-	91	(17)
Non-controlling interests	4	-	12 [13]	16	12	-	4 [13]	16
Net earnings (loss) attributable to TransAlta shareholders	16	-	(26)	(10)	(120)	-	87	(33)
Preferred share dividends	10	-	-	10	11	-	-	11
Net earnings (loss) attributable to common shareholders	6	-	(26)	(20)	(131)	-	87	(44)
Weighted average number of common shares outstanding in the period	288			288	279			279
Net earnings (loss) per share attributable to common shareholders	0.02			(0.07)	(0.47)			(0.16)

	6 months ended June 30, 2016				6 months ended June 30, 2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	1,060	62 [1, 2]	18 [4]	1,140	1,031	28 [1, 2]	73 [4]	1,132
Fuel and purchased power	382	(30) [3]	-	352	437	(30) [3]	-	407
Gross margin	678	92	18	788	594	58	73	725
Operations, maintenance, and administration	245	-	-	245	253	-	(1) [5]	252
Asset impairment charges (reversals)	-	-	-	-	(1)	-	1 [6]	-
Restructuring provision	-	-	-	-	7	-	(7) [7]	-
Taxes, other than income taxes	16	-	-	16	15	-	-	15
EBITDA	417	92	18	527	320	58	80	458
Depreciation and amortization	269	59 [2, 3]	-	328	270	32 [2, 3]	-	302
Operating income	148	33	18	199	50	26	80	156
Finance lease income	33	(33) [1]	-	-	26	(26) [1]	-	-
Foreign exchange gain (loss)	(6)	-	(4) [8]	(10)	(1)	-	1 [8]	-
Earnings before interest and taxes	175	-	14	189	75	-	81	156
Net interest expense	126	-	-	126	119	-	-	119
Income tax expense (recovery)	(42)	-	47 [9, 10, 11]	5	78	-	(76) [9, 10, 11, 12]	2
Net earnings (loss)	91	-	(33)	58	(122)	-	157	35
Non-controlling interests	1	-	41 [13]	42	26	-	4 [13]	30
Net earnings (loss) attributable to TransAlta shareholders	90	-	(74)	16	(148)	-	153	5
Preferred share dividends	22	-	-	22	23	-	-	23
Net earnings (loss) attributable to common shareholders	68	-	(74)	(6)	(171)	-	153	(18)
Weighted average number of common shares outstanding in the period	288			288	278			278
Net earnings (loss) per share attributable to common shareholders	0.24			(0.02)	(0.62)			(0.06)

Financial Instruments

Refer to Note 13 of the notes to the audited annual consolidated financial statements within our 2015 Annual Integrated Report and Note 7 of our unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2016 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2015 Annual Integrated Report and Note 8 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, 2015.

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.

We may also have various 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 must be derived by reference to a forecast that is based on a combination of external and internal fundamental modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for specified prices with counterparties that we believe to be creditworthy.

As at June 30, 2016, total Level III financial instruments had a net asset carrying value of $740 million (Dec. 31, 2015 - $542 million net asset). The increase during the period is attributable to a decrease in estimated long-term power prices on a 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, and maturities of unit contingent power purchase contracts, partially offset by unfavourable changes in foreign exchange rates due to the weakening of the US dollar relative to the Canadian dollar.

2016 Financial Outlook

Despite continuing low prices in Alberta and the Pacific Northwest, our expected key financial target ranges for 2016 remain as previously disclosed:

Measure	Target
Comparable EBITDA	$990 million to $1,100 million
Comparable FFO	$755 million to $835 million
Comparable FCF	$250 million to $300 million
Dividend	$0.16 per share, 15 to 18 per cent payout of Comparable FCF

Market

For 2016, power prices in Alberta are expected to be substantially lower than 2015 as a result of persistent low natural gas prices, low demand growth, the current level of supply, and virtually no strategic offer behavior by market participants. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, prices have been lower in 2016 due to low natural gas prices and increased hydro generation, however, we expect prices will be comparable to last year for the remainder of 2016. We do not have significant uncontracted positions in other jurisdictions.

Operations

Availability and Operating Costs

Availability of our coal fleet in Canada is expected to be in the range of 87 to 89 per cent in 2016. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent. All of our businesses are sustaining cost reduction initiatives completed in 2015. We continue to explore ways to further reduce our costs and be more competitive.

Contracted Cash Flows

As a result of Alberta PPAs and long-term contracts, approximately 75 per cent of our capacity is contracted over the next two years. This is reduced to 65 per cent when our Alberta PPAs for Sundance units 1 and 2 expire in 2017. More than half of our non-contracted generation is sold forward 12 to 18 months ahead of time using short-term physical or financial contracts, such that on an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming calendar year. As at the end of the second quarter, approximately 88 per cent of our 2016 capacity was contracted. The average prices of our short-term physical and financial contracts for 2016 are approximately $50 per MWh in Alberta and approximately US$40 per MWh in the Pacific Northwest.

Fuel Costs

Mining costs at our Alberta coal mine are expected to decrease in 2016 due to improved efficiency, lower diesel costs, and production improvements. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2016, on a standard cost per tonne basis, are expected to be one to two per cent lower than 2015 unit costs.

In the Pacific Northwest, our U.S. Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal is purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for the remainder of 2016 is expected to decrease by approximately 14 per cent due primarily to favourable renegotiations to reduce costs with our suppliers.

The value of coal inventories is assessed for impairment at the end of each reporting period.

Most of our generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provision, we typically purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

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

Energy Marketing

EBITDA from our Energy Marketing Segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2016 objective for Energy Marketing is to contribute between $70 million to $90 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies

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

Interest Expense

Interest expense on debt for 2016 is expected to be in-line with 2015. 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. Most of our debt is at fixed interest rates.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities.

Income Taxes

The effective tax rate on earnings, excluding non-comparable items for 2016, is expected to be approximately 10 to 15 per cent, which is lower than the statutory tax rate of 27 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital Expenditures

Our major projects are focused on sustaining our current operations and supporting our growth strategy.

Growth and Major Project Expenditures

A summary of the significant growth and major projects that are in progress is outlined below:

	Total Project		2016	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
South Hedland power project[2]	593	289	117	Q2 2017	150 MW combined cycle power plant
Solomon load bank facility	5	2	3	Q4 2016	Installation of 20MW load bank facility required to support the operation of the Solomon power station
Transmission	Not applicable [3]		13	Ongoing	Regulated transmission that receives a return on investment
Total	**598**	**291**	**133**		

Cash required to fund the construction of the South Hedland power project is expected to be partially funded by proceeds from project financing and cash generated by our business.

(1) As at June 30, 2016.

(2) Estimated project spend is AUD$570 million. Total estimated project spend is stated in CAD$ and includes estimated capital interest costs. The total estimated project spend may change due to fluctuation in foreign exchange rates.

(3) Transmission projects are aggregated and develop on an ongoing basis. Consequently, discrete project spend is not available.

Sustaining and Productivity Expenditures

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of property, plant, and equipment and are amortized on a straight-line basis over the term until the next major maintenance event. Excluded are 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 2016
Routine capital[2]	Capital required to maintain our existing generating capacity	34	90 - 95
Planned major maintenance	Regularly scheduled major maintenance	76	155 - 165
Mine capital	Capital related to mining equipment and land purchases	7	30 - 35
Finance leases	Payments on finance leases	8	15 - 20
Total sustaining capital excluding flood-recovery capital		**125**	**290- 315**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	-	5
Total sustaining capital		**125**	**295 - 320**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	4	10 - 15
Total sustaining and productivity capital		**129**	**305 - 345**

Planned major outages for 2016 include full major turnarounds of two Canadian Coal units that we operate, and two that our partners operate. Our revised plan also included two limited scope turnarounds on units we operate. Our planned outages also include significant work at our hydro facilities, including a stator/generator replacement.

One of our partners completed a major turnaround of one Canadian Coal unit that we do not operate in the first quarter of 2016, and in April we completed the planned outage of one unit that we operate. The two limited scope turnaround projects were also completed in the first quarter. As a result, we now have only one more planned major outage at the Canadian Coal facilities that we operate for the rest of this year, and one at units that our partners operate.

Since the beginning of the year, we reduced our estimate of planned major maintenance by approximately $35 million, to reflect the reduced scope of a major turnaround, deferral of the Ghost river diversion project to a subsequent year, the deferral of an inspection of a gas turbine in Sarnia, and discretionary projects.

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, and limited-scope major maintenance projects executed during unplanned outages, is estimated as follows for 2016:

	Coal	Gas and Renewables	Total	Lost to date[1]
GWh lost	855 - 865	50 - 60	905 - 925	481

In the first quarter, we reduced our estimate of lost production for Coal as compared to our estimates disclosed in our Annual MD&A due to reduced maintenance activities. In the second quarter, lower than expected production was lost during an outage. As a result, our full year 2016 estimate for Coal continues to be lower than the estimate disclosed in our Annual MD&A. The lower lost production estimate~~s~~ for Gas and Renewables compared to Dec. 31, 2015 is due to the deferral of major inspection work.

Funding for these capital expenditures is expected to be provided by cash flow from operating activities.

(1) *As at June 30, 2016.*
(2) *Includes hydro life extension spend.*

Accounting Changes

A. Current Accounting Changes

I. Operating and Reportable Segments

At the beginning of the first quarter, we have chosen to disaggregate presentation of the Gas reportable segment into its two operating segments, Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been re-allocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Restatement of a Prior Quarter

During the fourth quarter of 2015, we restated the statement of earnings of the first quarter of 2015 to increase non-comparable deferred tax expense by $47 million. As a result, net earnings attributable to common shareholders of the first quarter of 2015 and the six months ended June 30, 2015 decreased from $7 million to a net loss of $40 million and decreased from $75 million to a net loss of $122 million, respectively. The adjustment is due to the correction of the tax basis of an internally transferred asset as part of the reorganization of companies giving effect to the sale of an economic interest in Australian assets to TransAlta Renewables, which closed during the second quarter of 2015. Comparative information for the six months ended June 30, 2015 presented in this document has been adjusted accordingly.

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB but are not yet effective and have not been applied include IFRS 9 *Financial Instruments*, IFRS 15 *Revenue from Contracts with Customers,* and IFRS 16 *Leases*. Refer to *Note 3* of the most recent annual consolidated financial statements for information regarding the requirements of IFRS 9, IFRS 15, and IFRS 16.

In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property, and transition practical expedients. Amendments are effective for annual periods beginning on or after Jan. 1, 2018, consistent with IFRS 15.

The Corporation continues to assess the impact of adopting these standards on its consolidated financial statements.

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.

	Q3 2015	Q4 2015	Q1 2016	**Q2 2016**
Revenues	641	595	568	**492**
Comparable EBITDA	219	268	279	**248**
Comparable FFO	126	243	196	**175**
Net earnings (loss) attributable to common shareholders	154	(7)	62	**6**
Comparable net earnings (loss) attributable to common shareholders	(33)	3	14	**(20)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	0.55	(0.02)	0.22	**0.02**
Comparable net earnings (loss) per share, basic and diluted[(1)]	(0.12)	0.01	0.05	**(0.07)**

	Q3 2014	Q4 2014	Q1 2015 **Restated*	Q2 2015
Revenues	639	718	593	438
Comparable EBITDA	212	301	275	183
Comparable FFO	145	225	211	160
Net earnings (loss) attributable to common shareholders	(6)	148	(40)	(131)
Comparable net earnings (loss) attributable to common shareholders	(13)	46	26	(44)
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	(0.03)	0.54	(0.14)	(0.47)
Comparable net earnings (loss) per share, basic and diluted[(1)]	(0.05)	0.17	0.09	(0.16)

** See Accounting Changes for restatement.*

(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.

Comparable net earnings, comparable EBITDA, and comparable 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. Market volatility can also impact quarterly contributions from our Energy Marketing Segment. Following sales of non-controlling interest in TransAlta Renewables in the second quarter of 2015, the fourth quarter of 2015, and the first quarter of 2016, an increasing portion of earnings is attributable to non-controlling interests.

Revenues are impacted by market and operational factors listed above, and by changes in future power prices in the Pacific Northwest, which cause de-designated and economic hedges in the region to fluctuate in value. These hedges significantly depreciated in the second quarter of 2014 and first half of 2015, and significantly increased in value in the second half of 2014 over the third quarter of 2015. Revenues in the fourth quarter of 2015 were also impacted by a significant increase to a provision related to Force Majeure events associated mostly to prior years.

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

- gain on disposal of assets, following the Poplar Creek contract restructuring in the third quarter of 2015;
- Market Surveillance Administrator provision in the third quarter of 2015;
- a recovery of a writedown of deferred tax assets in the fourth quarter of 2014, a recovery in the third quarter of 2014, and a recovery in the first quarter of 2016;
- change in income tax rates in Alberta in the second quarter of 2015;
- deferred income tax impacts of the sale of an economic interest in Australian assets to TransAlta Renewables transaction in the first and second quarters of 2015; and
- effects of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first and second quarters of 2016.

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.

During the first quarter of 2016, we completed the implementation of a new energy trading and risk management system. In connection with the implementation, we updated the processes that constitute our internal control over financial reporting, as necessary, to accommodate related changes to our business processes and accounting procedures.

Except as otherwise described above, there have been no other changes in our internal control over financial reporting during the six months ended June 30, 2016 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 of June 30, 2016, 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 June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Unaudited				*(Restated)**
Revenues	**492**	438	**1,060**	1,031
Fuel and purchased power	**174**	200	**382**	437
Gross margin	**318**	238	**678**	594
Operations, maintenance, and administration	**122**	119	**245**	253
Depreciation and amortization	**147**	137	**269**	270
Asset impairment reversal	**-**	(1)	**-**	(1)
Restructuring	**-**	-	**-**	7
Taxes, other than income taxes	**8**	8	**16**	15
Operating income (loss)	**41**	(25)	**148**	50
Finance lease income	**17**	13	**33**	26
Net interest expense *(Note 4)*	**(62)**	(59)	**(126)**	(119)
Foreign exchange losses	**-**	(2)	**(6)**	(1)
Earnings (loss) before income taxes	**(4)**	(73)	**49**	(44)
Income tax expense (recovery) *(Note 5)*	**(24)**	35	**(42)**	78
Net earnings (loss)	**20**	(108)	**91**	(122)
Net earnings (loss) attributable to:				
TransAlta shareholders	**16**	(120)	**90**	(148)
Non-controlling interests *(Note 6)*	**4**	12	**1**	26
	20	(108)	**91**	(122)
Net earnings (loss) attributable to TransAlta shareholders	**16**	(120)	**90**	(148)
Preferred share dividends *(Note 12)*	**10**	11	**22**	23
Net income (loss) attributable to common shareholders	**6**	(131)	**68**	(171)
Weighted average number of common shares outstanding in the period *(millions)*	**288**	279	**288**	278
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.02**	(0.47)	**0.24**	(0.62)

** See Note 2(A) for prior period restatements.*
See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Comprehensive Income (Loss)
(in millions of Canadian dollars)

Unaudited	3 months ended June 30 2016	3 months ended June 30 2015	6 months ended June 30 2016	6 months ended June 30 2015 (Restated)*
Net earnings (loss)	**20**	(108)	**91**	(122)
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**(16)**	16	**(36)**	2
Gains on derivatives designated as cash flow hedges, net of tax(2)	**1**	-	**1**	2
Total items that will not be reclassified subsequently to net earnings	**(15)**	16	**(35)**	4
Gains (losses) on translating net assets of foreign operations(3)	**(5)**	(36)	**(129)**	74
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(4)	**-**	23	**62**	(41)
Gains (losses) on derivatives designated as cash flow hedges, net of tax(5)	**93**	(61)	**101**	91
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax(6)	**(26)**	21	**12**	(54)
Total items that will be reclassified subsequently to net earnings	**62**	(53)	**46**	70
Other comprehensive income (loss)	**47**	(37)	**11**	74
Total comprehensive income (loss)	**67**	(145)	**102**	(48)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**68**	(162)	**103**	(82)
Non-controlling interests *(Note 6)*	**(1)**	17	**(1)**	34
	67	(145)	**102**	(48)

** See Note 2(A) for prior period restatements.*

(1) Net of income tax recovery of 6 and 13 for the three and six months ended June 30, 2016 (2015 - 4 expense and 1 recovery), respectively.

(2) Net of income tax expense of nil for the three and six months ended June 30, 2016 (2015 - nil).

(3) Net of income tax expense of nil and 10 for the three and six months ended June 30, 2016 (2015 - nil), respectively.

(4) Net of income tax expense of 6 and 10 for the three and six months ended June 30, 2016 (2015 - 2 expense and 7 recovery), respectively.

(5) Net of income tax expense of 44 and 69 for the three and six months ended June 30, 2016 (2015 - 9 recovery and 38 expense), respectively.

(6) Net of income tax expense of 14 and 17 for the three and six months ended June 30, 2016 (2015 - 12 recovery and 13 expense), respectively.

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Financial Position
(in millions of Canadian dollars)

Unaudited	June 30, 2016	Dec. 31, 2015
Cash and cash equivalents	93	54
Trade and other receivables *(Note 8)*	452	567
Prepaid expenses	46	26
Risk management assets *(Notes 7 and 8)*	249	298
Inventory	238	219
	1,078	1,164
Long-term portion of finance lease receivables	733	775
Property, plant, and equipment *(Note 9)*		
Cost	12,784	12,854
Accumulated depreciation	(5,836)	(5,681)
	6,948	7,173
Goodwill	464	465
Intangible assets	358	369
Deferred income tax assets	72	71
Risk management assets *(Notes 7 and 8)*	751	797
Other assets	140	133
Total assets	10,544	10,947
Accounts payable and accrued liabilities	299	334
Current portion of decommissioning and other provisions	158	166
Risk management liabilities *(Notes 7 and 8)*	107	200
Income taxes payable	1	3
Dividends payable *(Note 11)*	26	63
Current portion of long-term debt and finance lease obligations *(Note 10)*	586	87
	1,177	853
Credit facilities, long-term debt, and finance lease obligations *(Note 10)*	3,528	4,408
Decommissioning and other provisions	208	232
Deferred income tax liabilities	652	647
Risk management liabilities *(Notes 7 and 8)*	33	69
Defined benefit obligation and other long-term liabilities	396	348
Equity		
Common shares *(Note 11)*	3,093	3,075
Preferred shares *(Note 12)*	942	942
Contributed surplus	9	9
Deficit	(985)	(1,018)
Accumulated other comprehensive income	366	353
Equity attributable to shareholders	3,425	3,361
Non-controlling interests *(Note 6)*	1,125	1,029
Total equity	4,550	4,390
Total liabilities and equity	10,544	10,947

Commitments and contingencies *(Note 13)*

Subsequent events *(Note 15)*

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

6 months ended June 30, 2016

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings	-	-	-	90	-	90	1	91
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	(67)	(67)	-	(67)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	103	103	11	114
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(36)	(36)	-	(36)
Intercompany available-for-sale investments	-	-	-	-	13	13	(13)	-
Total comprehensive income (loss)				90	13	103	(1)	102
Common share dividends	-	-	-	(23)	-	(23)	-	(23)
Preferred share dividends	-	-	-	(22)	-	(22)	-	(22)
Changes in non-controlling interests in TransAlta Renewables	-	-	-	(12)	-	(12)	176	164
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(79)	(79)
Common shares issued	18	-	-	-	-	18	-	18
Balance, June 30, 2016	**3,093**	**942**	**9**	**(985)**	**366**	**3,425**	**1,125**	**4,550**

See accompanying notes.

6 months ended June 30, 2015

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit *(Restated)**	Accumulated other comprehensive income (loss)	Attributable to shareholders *(Restated)**	Attributable to non-controlling interests	Total *(Restated)**
Balance, Dec. 31, 2014	2,999	942	9	(770)	104	3,284	594	3,878
Net earnings (loss)	-	-	-	(148)	-	(148)	26	(122)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	33	33	-	33
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	35	35	4	39
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	2	2	-	2
Intercompany available-for-sale-investments	-	-	-	-	(4)	(4)	4	-
Total comprehensive income (loss)				(148)	66	(82)	34	(48)
Common share dividends	-	-	-	(100)	-	(100)	-	(100)
Preferred share dividends	-	-	-	(23)	-	(23)	-	(23)
Changes in non-controlling interests in TransAlta Renewables	-	-	-	(14)	-	(14)	229	215
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(44)	(44)
Common shares issued	38	-	-	-	-	38	-	38
Balance, June 30, 2015	3,037	942	9	(1,055)	170	3,103	813	3,916

** See Note 2(A) for prior period restatements.*

See accompanying notes.

TransAlta Corporation
Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Unaudited				*(Restated)**
Operating activities				
Net earnings (loss)	**20**	(108)	**91**	(122)
Depreciation and amortization	**161**	152	**297**	299
Gain on sale of assets	**1**	-	**1**	-
Accretion of provisions	**5**	5	**11**	10
Decommissioning and restoration costs settled	**(5)**	(8)	**(8)**	(13)
Deferred income tax expense (recovery) *(Note 5)* *(Restated)**	**(30)**	30	**(53)**	67
Unrealized losses from risk management activities	**22**	73	**20**	109
Unrealized foreign exchange (gains) losses	**(3)**	7	**2**	14
Provisions	**(8)**	5	**(7)**	(4)
Asset impairment reversals	**-**	(1)	**-**	(1)
Other non-cash items	**(4)**	4	**(14)**	2
Cash flow from operations before changes in working capital	**159**	159	**340**	361
Change in non-cash operating working capital balances	**(40)**	(198)	**54**	(247)
Cash flow from operating activities	**119**	(39)	**394**	114
Investing activities				
Additions to property, plant, and equipment *(Note 9)*	**(76)**	(123)	**(161)**	(247)
Additions to intangibles	**(5)**	(7)	**(9)**	(13)
Proceeds on sale of property, plant, and equipment	**-**	1	**1**	2
Realized gains on financial instruments	**15**	8	**17**	2
Net decrease in collateral paid to counterparties	**-**	4	**-**	-
Decrease in finance lease receivable	**15**	1	**29**	2
Other	**-**	-	**1**	-
Change in non-cash investing working capital balances	**(25)**	-	**(21)**	(5)
Cash flow used in investing activities	**(76)**	(116)	**(143)**	(259)
Financing activities				
Net increase (decrease) in borrowings under credit facilities *(Note 10)*	**-**	22	**(315)**	605
Repayment of long-term debt	**(74)**	(1)	**(64)**	(634)
Issuance of long-term debt *(Note 10)*	**159**	-	**159**	45
Dividends paid on common shares *(Note 11)*	**(12)**	(31)	**(46)**	(61)
Dividends paid on preferred shares *(Note 12)*	**(10)**	(11)	**(22)**	(23)
Net proceeds on sale of non-controlling interest in subsidiary *(Note 3)*	**-**	211	**162**	211
Realized gains on financial instruments	**-**	1	**-**	77
Distributions paid to subsidiaries' non-controlling interests *(Note 6)*	**(37)**	(22)	**(76)**	(41)
Decrease in finance lease obligation	**(5)**	(4)	**(8)**	(7)
Change in non-cash financing working capital balances	**-**	1	**-**	1
Other	**(1)**	(1)	**-**	(1)
Cash flow from (used in) financing activities	**20**	165	**(210)**	172
Cash flow from operating, investing, and financing activities	**63**	10	**41**	27
Effect of translation on foreign currency cash	**-**	-	**(2)**	1
Increase in cash and cash equivalents	**63**	10	**39**	28
Cash and cash equivalents, beginning of period	**30**	61	**54**	43
Cash and cash equivalents, end of period	**93**	71	**93**	71
Cash income taxes paid	**7**	3	**15**	17
Cash interest paid	**94**	85	**115**	126

** See Note 2(A) for prior period restatements.*

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 Committee on behalf of the Board of Directors on Aug. 8, 2016.

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. An additional judgment applied in the first quarter of 2016 with respect to operating and reportable segments is described in *Note 2(A).*

2. Significant Accounting Policies

A. Current Accounting Changes

I. Operating and Reportable Segments

During the first quarter, the Corporation disaggregated presentation of the previous Gas reportable segment into its two operating segments; Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Restatement of a Prior Quarter

During the fourth quarter of 2015, the Corporation restated the statement of earnings of the first quarter of 2015 to increase deferred tax expense by $47 million. As a result, net earnings attributable to common shareholders of the first quarter of 2015 and the six months ended June 30, 2015 decreased from $7 million to a net loss of $40 million and decreased from a net loss of $75 million to a net loss of $122 million, respectively. The adjustment is due to the correction of the tax basis of an internally transferred asset as part of the reorganization of companies giving effect to the sale of an economic interest in Australian assets to TransAlta Renewables Inc. ("TransAlta Renewables"), which closed during the second quarter of 2015. Comparative information for the six months ended June 30, 2015 presented in these financial statements has been adjusted accordingly.

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 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.

In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property, and transition practical expedients. Amendments are effective for annual periods beginning on or after Jan. 1, 2018, consistent with IFRS 15. The Corporation continues to assess the impact of adopting these standards on its consolidated financial statements.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings, except as noted above for the restatement of a prior quarter.

3. Significant Events

A. Closing of $159 million project financing of a Quebec wind asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables' indirect wholly-owned subsidiary, New Richmond Wind L.P. (the "Issuer"), closed a bond offering of approximately $159 million which is secured by a first ranking charge over all assets of the Issuer. The bonds are amortizing and bear interest from their date of issue at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

Net proceeds of the financing will be used to, among other things, make advances to Canadian Hydro Developers, Inc. on a subordinated basis pursuant to an intercompany loan agreement, the proceeds of which will be used to finance certain facilities of the Issuer's affiliates and for other general business purposes.

The assets consist of the 68 MW New Richmond wind facility located in the Gaspé Peninsula near the town of New Richmond, Québec which began commercial operations in March 2013. The wind project is 100% contracted to Hydro-Québec for a term of 20 years from commercial operations and utilizes proven Enercon turbine technology.

B. Investment in Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility by TransAlta Renewables

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Sarnia cogeneration plant, Le Nordais wind farm, and Ragged Chute hydro facility (the "Canadian Assets") for a combined value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Quebec. The transaction was originally announced on Nov. 23, 2015. The Corporation will continue to own, manage, and operate the Canadian Assets.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30th and December 31st, and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of $13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation through issuance of common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery. On Jan. 6, 2016, TransAlta Renewables declared a dividend increase of 5 per cent.

4. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Interest on debt	**58**	56	**118**	113
Capitalized interest	**(4)**	(2)	**(7)**	(5)
Loss on redemption of bonds *(Note 10)*	**1**	-	**1**	-
Interest on finance lease obligations	**1**	-	**2**	1
Other	**1**	-	**1**	-
Accretion of provisions	**5**	5	**11**	10
Net interest expense	**62**	59	**126**	119

5. Income Taxes

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

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
				*(Restated)**
Current income tax expense	**6**	5	**11**	12
Adjustments in respect of current income tax of prior periods	**-**	-	**-**	(1)
Adjustments in respect of deferred income tax of prior periods	**-**	(2)	**-**	(2)
Deferred income tax recovery related to the origination and reversal of temporary differences	**(10)**	(31)	**(11)**	(34)
Deferred income tax expense related to temporary difference on investment in subsidiary(1)	**3**	40	**3**	95
Deferred income tax expense resulting from changes in tax rates or laws(2)	**-**	20	**1**	20
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets(3)	**(23)**	3	**(46)**	(12)
Income tax expense (recovery)	**(24)**	35	**(42)**	78

** See Note 2(A) for prior period restatements.*

(1) In order to give effect to the sale of an economic interest in Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a $40 million and $95 million deferred tax liability on TransAlta's investment in a subsidiary for the three and six months ended June 30, 2015, respectively. The deferred tax liability had not been recognized previously, as prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

(2) 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016. 2015 relates to the impact of an increase in the Alberta corporate income tax rate from 10 per cent to 12 per cent, enacted June 18, 2015.

(3) As disclosed in previous periods, the Corporation had written certain deferred tax assets off as it was no longer considered probable that sufficient future taxable income would be available to utilize the underlying tax losses. In the second quarter of 2016, the Corporation's views on the ability to utilize the underlying tax losses improved based on unrealized gains on investments and hedging instruments, such that a reversal of the previous writedowns were warranted. As a result, for the three months ended June 30, 2016 the Corporation recorded a recovery of $23 million (June 30, 2015 - $3 million writedown) and for the six months ended June 30, 2016, the Corporation recorded a recovery of $46 million (June 30, 2015 - $12 million).

Presented in the Condensed Consolidated Statements of Earnings as follows:

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
				*(Restated)**
Current income tax expense	**6**	5	**11**	11
Deferred income tax expense (recovery)	**(30)**	30	**(53)**	67
Income tax expense (recovery)	**(24)**	35	**(42)**	78

** See Note 2(A) for prior period restatements.*

6. Non-Controlling Interests

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

Amounts attributable to the non-controlling interests include the 17 per cent non-controlling interest in its Kent Hills wind farm.

The Corporation's share of ownership and equity participation were as follows over the current and comparative periods:

Period	Ownership and voting rights percentage	Equity participation percentage
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 and thereafter	64.0	59.8

As the Class B shares in the capital of TransAlta Renewables issued to the Corporation were determined to constitute financial liabilities of TransAlta Renewables and do not participate in earnings until commissioning of South Hedland, expected in mid-2017, they are excluded from the allocation of equity and earnings.

	3 months ended June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Revenues	**52**	51	**120**	119
Net earnings (loss)	**(14)**	8	**(49)**	29
Total comprehensive income (loss)	**(45)**	23	**(82)**	44
Amounts attributable to the non-controlling interests:				
Net earnings (loss)	**(4)**	3	**(18)**	10
Total comprehensive income (loss)	**(17)**	7	**(31)**	14
Distributions paid to non-controlling interests	**21**	9	**41**	17

As at	June 30, 2016	Dec. 31, 2015
Current assets	**71**	74
Long-term assets	**3,741**	3,262
Current liabilities	**(432)**	(190)
Long-term liabilities	**(1,223)**	(1,120)
Total equity	**(2,157)**	(2,026)
Equity attributable to non-controlling interests	**(888)**	(787)
Non-controlling interests share (per cent)	**40.2**	38.0

B. TransAlta Cogeneration L.P.

	3 months ended June 30		6 months ended June 30	
	2016	2015	2016	2015
Revenues	71	69	148	144
Net earnings	17	17	38	32
Total comprehensive income	32	21	59	40
Amounts attributable to the non-controlling interest:				
Net earnings	8	9	19	16
Total comprehensive income	16	10	30	20
Distributions paid to the non-controlling interest	16	13	35	24

As at	June 30, 2016	Dec. 31, 2015
Current assets	65	82
Long-term assets	499	535
Current liabilities	(53)	(75)
Long-term liabilities	(33)	(54)
Total equity	(478)	(488)
Equity attributable to the non-controlling interest	(237)	(242)
Non-controlling interest share (per cent)	49.99	49.99

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

b. Level II

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

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

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

In determining Level II fair values of other risk management assets 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 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 (the "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. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of 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	June 30, 2016		Dec. 31, 2015	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	922	+72 -77	863	+125 -186
Long-term power sale - Alberta	(8)	+6 -5	(13)	+13 -7
Unit contingent power purchases	(17)	+4 -4	(70)	+9 -8
Structured products - Eastern U.S.	21	+9 -9	18	+6 -4
Hydro slice products - Western U.S.	-	+2 -1	(6)	+1 -4
Others	7	+3 -3	(3)	+2 -2

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: 280 MW through Nov. 30, 2016, 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 2017, 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 MWh used in determining the Level III base fair value at June 30, 2016 are US$27 - US$39 (Dec. 31, 2015 - US$28 - US$45).

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2015 to June 30, 2016, the base fair value and the sensitivity values have decreased by approximately $56 million and $5 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 June 30, 2016 are $70 - $97 (Dec. 31, 2015 - $86 - $93).

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.

In particular, a one standard deviation movement upward and downward in the volumetric and price discount rates was assessed. This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at June 30, 2016 are 0 per cent to 2.8 per cent (Dec. 31, 2015 - 0 per cent to 2.8 per cent) and 1.7 per cent to 7.4 per cent (Dec. 31, 2015 – 1.7 per cent to 7.4 per cent), respectively.

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 June 30, 2016 are 77 per cent to 129 per cent and 65 per cent to 110 per cent (Dec. 31, 2015 – 85 per cent to 116 per cent and 65 per cent to 109 per cent), respectively.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at June 30, 2016 are 20 per cent to 48 per cent and 60 per cent to 80 per cent (Dec. 31, 2015 – 18 per cent to 71 per cent and 39 per cent to 80 per cent), respectively.

v. Hydro Slice Products – Western U.S.

The Corporation has agreed to purchase power contingent upon the actual generation of specific hydro units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed capacity payment. The contracts are accounted for as held for trading.

The key unobservable inputs used in the valuations are delivered volume expectations. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements. This analysis is based on historical production of the generation units for available history. Volumes used in the Level III base fair value measurement at June 30, 2016 are within the 50th percentile of the historical production (Dec. 31, 2015 – 50th percentile).

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.

The following tables summarize the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the six months ended June 30, 2016 and 2015, respectively:

	Hedges			Non-Hedges			Total		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets (liabilities) at Dec. 31, 2015	-	(58)	640	-	128	(98)	-	70	542
Changes attributable to:									
Market price changes on existing contracts	-	22	175	-	(19)	30	-	3	205
Market price changes on new contracts	-	1	-	-	(14)	4	-	(13)	4
Contracts settled	-	7	(20)	-	(94)	72	-	(87)	52
Change in foreign exchange rates	-	4	(65)	-	(3)	2	-	1	(63)
Net risk management assets (liabilities) at June 30, 2016	-	(24)	730	-	(2)	10	-	(26)	740
Additional Level III information:									
Gains recognized in OCI			110			-			110
Total gains included in earnings before income taxes			20			36			56
Unrealized gains included in earnings before income taxes relating to net liabilities held at June 30, 2016			-			108			108

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	-	(19)	121	-	8	(32)	-	(11)	89
Market price changes on new contracts	-	(50)	-	-	(26)	(7)	-	(76)	(7)
Contracts settled	-	12	(11)	-	(107)	51	-	(95)	40
Change in foreign exchange rates	-	(5)	34	-	7	(4)	-	2	30
Net risk management assets (liabilities) at June 30, 2015	-	(121)	458	-	62	(89)	-	(59)	369
Additional Level III information:									
Gains recognized in OCI			155			-			155
Total gains (losses) included in earnings before income taxes			11			(43)			(32)
Unrealized gains included in earnings before income taxes relating to net liabilities held at June 30, 2015			-			8			8

Significant changes in commodity net risk management assets (liabilities) during the six months ended June 30, 2016 are primarily attributable to the following factors:

- 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;
- maturity of power contracts in the Northeast US (Level II non-hedge);
- maturities of unit contingent power purchases described in the section (B)(I)(c)(iii) of this note (Level III non-hedges); and
- changes in foreign exchange rates that impact the long-term power sale contract (Level III hedge).

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy marketing transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks. Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

Other risk management assets and liabilities with a total net asset fair value of $146 million as at June 30, 2016 (Dec. 31, 2015 - $214 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended June 30, 2016 are primarily attributable to the weakening of the US dollar relative to the Canadian dollar on the Corporation's foreign currency hedges.

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 value
	Level I	Level II	Level III	Total	
Long-term debt[1] - June 30, 2016	**-**	**3,806**	**-**	**3,806**	**3,973**
Long-term debt[1] - Dec. 31, 2015	-	4,067	-	4,067	4,344

(1) Includes current portion and excludes $65 million (Dec. 31, 2015 - $69 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 and other accounts receivable, accounts payable and accrued liabilities, 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 June 30		6 months ended June 30	
	2016	2015	**2016**	2015
Unamortized net gain at beginning of period	**174**	185	**202**	188
New inception gains	**2**	16	**4**	17
Change in foreign exchange rates	**1**	(5)	**(11)**	11
Amortization recorded in net earnings during the period	**(20)**	(7)	**(38)**	(27)
Unamortized net gain at end of period	**157**	189	**157**	189

8. Risk Management Activities

A. Net Risk Management Assets and Liabilities

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

As at June 30, 2016	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	42	-	12	54
Long-term	-	664	-	(4)	660
Net commodity risk management assets	-	706	-	8	714
Other					
Current	(3)	90	-	1	88
Long-term	-	57	5	(4)	58
Net other risk management assets (liabilities)	(3)	147	5	(3)	146
Total net risk management assets (liabilities)	(3)	853	5	5	860

As at Dec. 31, 2015	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	31	-	57	88
Long-term	-	551	-	(27)	524
Net commodity risk management assets	-	582	-	30	612
Other					
Current	(7)	20	-	(3)	10
Long-term	-	207	5	(8)	204
Net other risk management assets (liabilities)	(7)	227	5	(11)	214
Total net risk management assets (liabilities)	(7)	809	5	19	826

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. Commodity Price Risk

Value at Risk ("VaR") is the most commonly used metric employed to track and manage the market risk associated with commodity and other derivatives. 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.

a. 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.

VaR at June 30, 2016 associated with the Corporation's proprietary trading activities was $2 million (Dec. 31, 2015 - $5 million).

b. Commodity Price Risk - Generation

Various commodity contracts and other financial instruments are used to manage the commodity price risk associated with the Corporation's electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. VaR at June 30, 2016 associated with the Corporation's commodity derivative instruments used in these hedging activities was $29 million (Dec. 31, 2015 - $24 million). VaR at June 30, 2016 associated with positions and economic hedges that do not meet hedge accounting requirements was $3 million (Dec. 31, 2015 - $1 million).

II. Currency Rate Risk

The Corporation has exposure to various currencies, such as the euro, the US dollar, the Japanese yen, 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.

III. 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 fulfill their obligations under the related contracts prior to entering into such contracts. TransAlta is exposed to minimal credit risk for Alberta Coal PPAs as receivables are substantially all secured by letters of credit.

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. In certain cases, the Corporation will require security instruments such as parental guarantees, letters of credit, cash collateral or third party credit insurance to reduce overall credit risk. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at June 30, 2016:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[(1)]	91	9	100	452
Long-term finance lease receivables[(2)]	41	59	100	733
Risk management assets[(1)]	99	1	100	1,000
Total				2,185

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

(2) The Corporation has one non-investment grade customer whose outstanding balance accounted for $431 million (Dec. 31, 2015 - $446 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid- to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at June 30, 2016 was $16 million (Dec. 31, 2015 - $44 million).

IV. 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. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. As at June 30, 2016, TransAlta maintains investment grade ratings from three credit rating agencies. For further details refer to Note 14(B)(III) of the Corporation's most recent annual consolidated financial statements.

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

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Accounts payable and accrued liabilities	299	-	-	-	-	-	299
Long-term debt(1)	26	575	897	453	453	1,650	4,054
Commodity risk management (assets) liabilities	(24)	(59)	(56)	(72)	(77)	(426)	(714)
Other risk management (assets) liabilities	(1)	(90)	(57)	1	1	-	(146)
Finance lease obligations	8	15	13	9	7	24	76
Interest on long-term debt and finance lease obligations(2)	109	206	163	134	108	793	1,513
Dividends payable	26	-	-	-	-	-	26
Total	**443**	**647**	**960**	**525**	**492**	**2,041**	**5,108**

(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 June 30, 2016, the Corporation had posted collateral of $160 million (Dec. 31, 2015 - $220 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 $39 million (Dec. 31, 2015 - $44 million) of collateral to its counterparties.

9. 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(1)	Capital spares and other(2)	Total
As at Dec. 31, 2015	95	2,811	611	2,455	604	351	246	7,173
Additions	1	-	-	-	-	164	(4)	161
Additions - finance lease	-	-	-	-	2	-	-	2
Disposals	(1)	-	-	-	-	-	-	(1)
Depreciation	-	(143)	(38)	(63)	(22)	-	(8)	(274)
Revisions and additions to decommissioning and restoration costs	-	(8)	3	(3)	(5)	-	-	(13)
Retirement of assets	-	(8)	-	(1)	(1)	-	-	(10)
Change in foreign exchange rates	(1)	(23)	(8)	(20)	(4)	(15)	(6)	(77)
Transfers	-	75	1	20	9	(129)	11	(13)
As at June 30, 2016	**94**	**2,704**	**569**	**2,388**	**583**	**371**	**239**	**6,948**

(1) During the three months ended June 30, 2016, approximately $14 million of assets were transferred to the long-term finance lease receivables in relation to the gas reticulation work completed at the Corporation's Solomon Power Station.

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

10. 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	June 30, 2016			Dec. 31, 2015		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	-	-	-	315	315	3.1%
Debentures	1,045	1,051	6.0%	1,044	1,051	6.0%
Senior notes[3]	2,077	2,079	5.0%	2,221	2,221	4.9%
Non-recourse[4]	857	865	4.4%	766	773	4.5%
Other[5]	59	59	9.2%	67	67	9.3%
	4,038	4,054		4,413	4,427	
Finance lease obligations	76			82		
	4,114			4,495		
Less: current portion of long-term debt	(570)			(72)		
Less: current portion of finance lease obligations	(16)			(15)		
Total current long-term debt and finance lease obligations	(586)			(87)		
Total credit facilities, long-term debt, and finance lease obligations	3,528			4,408		

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

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

(3) US face value at June 30, 2016 - US$1.6 billion (Dec. 31, 2015 - US$1.6 billion).

(4) Includes US$53 million at June 30, 2016 (Dec. 31, 2015 - US$59 million).

(5) Includes US$33 million at June 30, 2016 (Dec. 31, 2015 - US$36 million) of tax equity financing.

During the second quarter:

- the Corporation's indirect wholly-owned subsidiary New Richmond Wind L.P. issued a non-recourse bond in the amount of $159 million, bearing interest at 3.963 per cent, with principal and interest payable semi-annually, and maturing on June 30, 2032 (See Note 3);
- the Corporation's $27 million 5.69 per cent non-recourse debenture matured and was paid out using existing liquidity;
- the Corporation made a scheduled semi-annual $17 million principal payment on the Melanchthon-Wolfe Wind bond; and
- the Corporation early redeemed $10 million of non-recourse bonds, which resulted in a $1 million loss recognized in interest expense.

During the first quarter, the Corporation paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian Assets that closed Jan. 6, 2016.

Of the $2.1 billion (Dec. 31, 2015 - $2.2 billion) of committed credit facilities, $1.5 billion (Dec. 31, 2015 - $1.3 billion) is not drawn. The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.5 billion available under the credit facilities, TransAlta also has $93 million of available cash and cash equivalents.

The total outstanding letters of credit as at June 30, 2016 was $607 million (Dec. 31, 2015 - $575 million) with no (Dec. 31, 2015 - nil) amounts exercised by third parties under these arrangements.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at June 30, 2016, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of $191 million (Dec. 31, 2015 - $230 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.

Other non-recourse debt of $666 million (Dec. 31, 2015 - $536 million) is subject to customary financing restrictions that 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 non-recourse debt are secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes renewable generation facilities with total carrying amounts of $976 million at June 30, 2016 (Dec. 31, 2015 - $798 million).

11. 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 June 30				6 months ended June 30			
	2016		2015		2016		2015	
	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	277.0	3,021	284.0	3,077	275.0	3,001
Issued under the dividend reinvestment and optional common share purchase plan	-	-	1.7	18	3.9	18	3.7	38
	287.9	3,095	278.7	3,039	287.9	3,095	278.7	3,039
Amounts receivable under Employee Share Purchase Plan	-	(2)	-	(2)	-	(2)	-	(2)
Issued and outstanding, end of period	287.9	3,093	278.7	3,037	287.9	3,093	278.7	3,037

B. Dividends and Shareholder Rights Plan

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually and the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP") effective immediately. These actions were taken as part of a plan to maximize the Corporation's long-term financial flexibility, as well as to stop shareholder dilution relating to the DRIP.

On April 21, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on July 1, 2016.

On April 22, 2016, the Shareholder Rights Plan discussed in Note 22 of the Corporation's most recent annual consolidated financial statements was renewed for a new period of approximately three years.

On July 19, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Oct. 1, 2016.

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 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.

12. Preferred Shares

A. Issued and Outstanding

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at June 30, 2016.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board. The annualized dividend rate for the Series B Shares for the 3-month floating rate period from and including June 30, 2016 to but excluding Sept. 30, 2016 is 2.569 per cent and will reset every quarter.

Additionally, at June 30, 2016, the Corporation also had 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G Cumulative Redeemable Rate Reset Preferred Shares issued and outstanding.

B. Dividends

The following table summarizes the preferred share dividends declared within the three and six months ended June 30, 2016 and 2015:

		3 months ended June 30		6 months ended June 30	
	Quarterly amounts	**2016**	2015	**2016**	2015
Series	per share	**Total**	Total	**Total**	Total
A	0.16931[(1)]	**1**	3	**5**	7
B	0.1549	**1**	-	**1**	-
C	0.2875	**3**	3	**6**	6
E	0.3125	**3**	3	**6**	6
G	0.33125	**2**	2	**4**	4
Total for the period		**10**	11	**22**	23

(1) For the three months ended March 31, 2016. For the six months ended June 30, 2015, the Corporation paid a quarterly amount of $0.2875 per share.

On July 19, 2016, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.16144 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable Sept. 30, 2016.

13. Contingencies and Commitments

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.

On July 5, 2016, the Corporation renewed one ten-year and two five-year long-term service agreements with three of its wind facilities to provide on-going maintenance. Total committed expenditures under the agreements are approximately $30 million.

14. Segment Disclosures

A. Reported Statement of Earnings (Loss)

3 months ended June 30, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	229	41	88	30	55	38	11	-	492
Fuel and purchased power	105	23	35	6	3	2	-	-	174
Gross margin	124	18	53	24	52	36	11	-	318
Operations, maintenance, and administration	43	12	14	6	14	10	5	18	122
Depreciation and amortization	64	27	14	1	29	6	-	6	147
Taxes, other than income taxes	3	1	-	-	2	1	-	1	8
Operating income (loss)	14	(22)	25	17	7	19	6	(25)	41
Finance lease income	-	-	4	13	-	-	-	-	17
Net interest expense									(62)
Earnings before income taxes									(4)

3 months ended June 30, 2015	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	205	23	110	30	49	38	(17)	-	438
Fuel and purchased power	99	44	47	5	2	3	-	-	200
Gross margin	106	(21)	63	25	47	35	(17)	-	238
Operations, maintenance, and administration	48	10	17	6	12	9	1	16	119
Depreciation and amortization	59	17	21	5	22	6	-	7	137
Asset impairment reversal	-	(1)	-	-	-	-	-	-	(1)
Taxes, other than income taxes	3	1	1	-	2	1	-	-	8
Operating income (loss)	(4)	(48)	24	14	11	19	(18)	(23)	(25)
Finance lease income	-	-	2	11	-	-	-	-	13
Net interest expense									(59)
Foreign exchange loss									(2)
Loss before income taxes									(73)

6 months ended June 30, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	463	97	193	59	139	66	43	-	1060
Fuel and purchased power	203	75	77	11	12	4	-	-	382
Gross margin	260	22	116	48	127	62	43	-	678
Operations, maintenance, and administration	88	24	28	12	26	17	14	36	245
Depreciation and amortization	125	24	28	6	59	13	1	13	269
Taxes, other than income taxes	6	2	1	-	4	2	-	1	16
Operating income (loss)	41	(28)	59	30	38	30	28	(50)	148
Finance lease income	-	-	7	26	-	-	-	-	33
Net interest expense									(126)
Foreign exchange loss									(6)
Earnings before income taxes									49

6 months ended June 30, 2015 (Restated - See Note 2)	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	451	74	251	56	122	63	14	-	1,031
Fuel and purchased power	212	91	114	10	6	4	-	-	437
Gross margin	239	(17)	137	46	116	59	14	-	594
Operations, maintenance, and administration	97	22	35	12	24	20	9	34	253
Depreciation and amortization	116	32	44	9	44	12	-	13	270
Asset impairment reversal	-	(1)	-	-	-	-	-	-	(1)
Restructuring provision	7	-	-	-	-	-	-	-	7
Taxes, other than income taxes	6	2	2	-	4	1	-	-	15
Operating income (loss)	13	(72)	56	25	44	26	5	(47)	50
Finance lease income	-	-	3	23	-	-	-	-	26
Net interest expense									(119)
Foreign exchange loss									(1)
Loss before income taxes									(44)

During the three and six months ended June 30, 2016, the Corporation recorded a $2 million reversal (2015 - $8 million reversal) and $4 million writedown (2015 - $2 million writedown), respectively, of coal inventory to its net realizable value. The writedown and reversal are included in fuel and purchased power of the U.S. Coal Segment.

Included in revenues of the Wind and Solar Segment for the three months and six months ended June 30, 2016 are $4 million (2015 - $4 million) and $11 million (2015 - $10 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

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

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

	3 months ended June 30		6 months ended June 30	
	2016	2015	2016	2015
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings (Loss)	147	137	269	270
Depreciation included in fuel and purchased power	14	15	28	29
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	161	152	297	299

15. Subsequent Events

Credit Facility Renewal

In August, the Corporation received commitments from its lenders to extend its syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018 respectively. All commitments are subject to finalizing loan documentation with key terms and covenants remaining unchanged.

Supplemental Information

		June 30, 2016	Dec. 31, 2015
Closing market price (TSX) ($)		6.72	4.91
Price range for the last 12 months (TSX) ($)	High	9.74	12.34
	Low	3.76	4.13
Adjusted net debt to invested capital[1] (%)		51.7	54.6
Adjusted net debt to invested capital excluding non-recourse debt[1] (%)		46.2	50.2
Adjusted net debt to comparable EBITDA[1, 2] (times)		4.3	5.0
Return on equity attributable to common shareholders[2] (%)		10.2	(1.2)
Comparable return on equity attributable to common shareholders[1, 2] (%)		(1.7)	(2.3)
Return on capital employed[2] (%)		6.2	4.6
Comparable return on capital employed[1, 2] (%)		3.3	3.0
Earnings coverage[2] (times)		1.9	1.5
Dividend payout ratio based on comparable funds from operations[1, 2, 3] (%)		17.5	28.3
Dividend coverage[2,3] (times)		6.9	3.6
Dividend yield[2,3]		8.6	14.7
Adjusted comparable FFO to adjusted net debt[2] (%)		16.5	15.2
Comparable FFO before interest to adjusted interest coverage[2] (times)		3.7	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 - cash and cash equivalents + 50 per cent issued preferred shares / comparable EBITDA

Return on equity attributable to common shareholders = net earnings attributable to common shareholders or earnings on a comparable basis / equity attributable to common shareholders excluding Accumulated Other Comprehensive Income ("AOCI")

(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 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.

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

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

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

Dividend coverage ratio = comparable cash flow from operating activities / cash dividends paid on common shares

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

Adjusted comparable funds from operations to adjusted net debt = comparable funds from operations - 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

Comparable funds from operations before interest to adjusted interest coverage = comparable funds from operations + interest on debt - interest income - capitalized interest / interest on debt + 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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