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	
Unaudited	**2017**	2016	**2017**	2016
Revenues	**503**	492	**1,081**	1,060
Fuel, purchased power, and other	**180**	174	**430**	382
Gross margin	**323**	318	**651**	678
Operations, maintenance, and administration	**127**	122	**252**	245
Depreciation and amortization	**154**	147	**297**	269
Asset impairment charge *(Note 3)*	**20**	-	**20**	-
Taxes, other than income taxes	**8**	8	**16**	16
Net other operating income *(Note 4)*	**(10)**	-	**(20)**	-
Operating income	**24**	41	**86**	148
Finance lease income	**16**	17	**32**	33
Net interest expense *(Note 5)*	**(59)**	(62)	**(121)**	(126)
Foreign exchange gains (losses)	**2**	-	**1**	(6)
Other income	**2**	-	**2**	-
Earnings (loss) before income taxes	**(15)**	(4)	**-**	49
Income tax recovery *(Note 6)*	**(19)**	(24)	**(36)**	(42)
Net earnings	**4**	20	**36**	91
Net earnings (loss) attributable to:				
TransAlta shareholders	**(8)**	16	**(8)**	90
Non-controlling interests *(Note 7)*	**12**	4	**44**	1
	4	20	**36**	91
Net earnings (loss) attributable to TransAlta shareholders	**(8)**	16	**(8)**	90
Preferred share dividends *(Note 13)*	**10**	10	**10**	22
Net earnings (loss) attributable to common shareholders	**(18)**	6	**(18)**	68
Weighted average number of common shares outstanding in the period *(millions)*	**288**	288	**288**	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.06)**	0.02	**(0.06)**	0.24

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

Unaudited	3 months ended June 30 2017	3 months ended June 30 2016	6 months ended June 30 2017	6 months ended June 30 2016
Net earnings	**4**	20	**36**	91
Net actuarial losses on defined benefit plans, net of tax(1)	**(13)**	(16)	**(12)**	(36)
Gains on derivatives designated as cash flow hedges, net of tax(2)	**-**	1	**-**	1
Total items that will not be reclassified subsequently to net earnings	**(13)**	(15)	**(12)**	(35)
Losses on translating net assets of foreign operations(3)	**(28)**	(5)	**(34)**	(129)
Reclassification of translation gains on net assets of divested foreign operations(4)	**(9)**	-	**(9)**	-
Gains on financial instruments designated as hedges of foreign operations, net of tax(5)	**10**	-	**23**	62
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax(6)	**14**	-	**14**	-
Gains on derivatives designated as cash flow hedges, net of tax(7)	**48**	93	**77**	101
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax(8)	**(39)**	(26)	**(45)**	12
Total items that will be reclassified subsequently to net earnings	**(4)**	62	**26**	46
Other comprehensive income (loss)	**(17)**	47	**14**	11
Total comprehensive income (loss)	**(13)**	67	**50**	102
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**(39)**	68	**(13)**	103
Non-controlling interests *(Note 7)*	**26**	(1)	**63**	(1)
	(13)	67	**50**	102

(1) Net of income tax recovery of 4 for the three and six months ended June 30, 2017 (2016 - 6 and 13 recovery), respectively.

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

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

(4) Net of income tax expense of 11 for the three and six months ended June 30, 2017.

(5) Net of income tax expense of 1 and 2 for the three and six months ended June 30, 2017 (2016 - 6 and 10 expense), respectively.

(6) Net of income tax recovery of 2 for the three and six months ended June 30, 2017.

(7) Net of income tax expense of 29 and 51 for the three and six months ended June 30, 2017 (2016 - 44 and 69 expense), respectively.

(8) Net of income tax expense of 21 and 31 for the three and six months ended June 30, 2017 (2016 - 14 and 17 expense), respectively.

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	June 30, 2017	Dec. 31, 2016
Cash and cash equivalents	50	305
Trade and other receivables *(Note 9)*	671	703
Prepaid expenses	58	23
Risk management assets *(Notes 8 and 9)*	220	249
Inventory	247	213
Assets held for sale *(Note 3)*	-	61
	1,246	1,554
Long-term portion of finance lease receivables	672	719
Property, plant, and equipment *(Note 10)*		
Cost	12,845	12,773
Accumulated depreciation	(6,141)	(5,949)
	6,704	6,824
Goodwill	464	464
Intangible assets	343	355
Deferred income tax assets	52	53
Risk management assets *(Notes 8 and 9)*	746	785
Other assets	192	242
Total assets	10,419	10,996
Accounts payable and accrued liabilities	421	413
Current portion of decommissioning and other provisions	34	39
Risk management liabilities *(Notes 8 and 9)*	70	66
Income taxes payable	12	6
Dividends payable *(Note 12)*	26	54
Current portion of long-term debt and finance lease obligations *(Note 11)*	943	639
	1,506	1,217
Credit facilities, long-term debt, and finance lease obligations *(Note 11)*	2,860	3,722
Decommissioning and other provisions	387	304
Deferred income tax liabilities	674	712
Risk management liabilities *(Notes 8 and 9)*	51	48
Defined benefit obligation and other long-term liabilities	341	330
Equity		
Common shares *(Note 12)*	3,094	3,094
Preferred shares *(Note 13)*	942	942
Contributed surplus	9	9
Deficit	(963)	(933)
Accumulated other comprehensive income	394	399
Equity attributable to shareholders	3,476	3,511
Non-controlling interests *(Note 7)*	1,124	1,152
Total equity	4,600	4,663
Total liabilities and equity	10,419	10,996

Commitments and contingencies *(Note 14)*

Subsequent events *(Note 16)*

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

6 months ended June 30, 2017

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Equity attributable to shareholders	Non-controlling interests	Total
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings (loss)	-	-	-	(8)	-	(8)	44	36
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	(6)	(6)	-	(6)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	32	32		32
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(12)	(12)	-	(12)
Intercompany available-for-sale-investments	-	-	-	-	(19)	(19)	19	-
Total comprehensive income (loss)				(8)	(5)	(13)	63	50
Common share dividends	-	-	-	(12)	-	(12)	-	(12)
Preferred share dividends	-	-	-	(10)	-	(10)	-	(10)
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(91)	(91)
Balance, June 30, 2017	**3,094**	**942**	**9**	**(963)**	**394**	**3,476**	**1,124**	**4,600**

See accompanying notes.

6 months ended June 30, 2016

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	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 of 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.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2017**	2016	**2017**	2016
Operating activities				
Net earnings	**4**	20	**36**	91
Depreciation and amortization *(Note 15)*	**173**	161	**333**	297
Gain on sale of assets	**-**	1	**-**	1
Accretion of provisions	**5**	5	**11**	11
Decommissioning and restoration costs settled	**(3)**	(5)	**(7)**	(8)
Deferred income tax recovery *(Note 6)*	**(25)**	(30)	**(48)**	(53)
Unrealized (gains) losses from risk management activities	**(28)**	22	**(33)**	20
Unrealized foreign exchange (gains) losses	**(1)**	(3)	**1**	2
Provisions	**-**	(8)	**-**	(7)
Asset impairment charges *(Note 3)*	**20**	-	**20**	-
Other items	**27**	(4)	**45**	(14)
Cash flow from operations before changes in working capital	**172**	159	**358**	340
Change in non-cash operating working capital balances	**(109)**	(40)	**(14)**	54
Cash flow from operating activities	**63**	119	**344**	394
Investing activities				
Additions to property, plant, and equipment *(Note 10)*	**(97)**	(76)	**(157)**	(161)
Additions to intangibles	**(6)**	(5)	**(10)**	(9)
Proceeds on sale of property, plant, and equipment	**-**	-	**-**	1
Proceeds on sale of facility (Wintering Hills) *(Note 3)*	**-**	-	**61**	-
Realized gains on financial instruments	**-**	15	**-**	17
Decrease in finance lease receivable	**15**	15	**30**	29
Other	**-**	-	**(2)**	1
Change in non-cash investing working capital balances	**14**	(25)	**9**	(21)
Cash flow used in investing activities	**(74)**	(76)	**(69)**	(143)
Financing activities				
Net increase (decrease) in borrowings under credit facilities	**100**	-	**100**	(315)
Repayment of long-term debt	**(573)**	(74)	**(587)**	(64)
Issuance of long-term debt	**-**	159	**-**	159
Dividends paid on common shares *(Note 12)*	**(11)**	(12)	**(23)**	(46)
Dividends paid on preferred shares *(Note 13)*	**(10)**	(10)	**(20)**	(22)
Net proceeds on sale of non-controlling interest in subsidiary	**-**	-	**-**	162
Realized gains on financial instruments	**107**	-	**107**	-
Distributions paid to subsidiaries' non-controlling interests *(Note 7)*	**(51)**	(37)	**(98)**	(76)
Decrease in finance lease obligation	**(5)**	(5)	**(9)**	(8)
Other	**1**	(1)	**-**	-
Cash flow from (used in) financing activities	**(442)**	20	**(530)**	(210)
Cash flow from (used in) operating, investing, and financing activities	**(453)**	63	**(255)**	41
Effect of translation on foreign currency cash	**(1)**	-	**-**	(2)
Increase (decrease) in cash and cash equivalents	**(454)**	63	**(255)**	39
Cash and cash equivalents, beginning of period	**504**	30	**305**	54
Cash and cash equivalents, end of period	**50**	93	**50**	93
Cash income taxes paid	**4**	7	**6**	15
Cash interest paid	**96**	94	**118**	115

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. 9, 2017.

B. Use of Estimates and Significant Judgments

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

2. Significant Accounting Policies

A. Current Accounting Changes

I. Change in Estimates – Useful Lives

As a result of the Off-Coal Arrangement ("OCA") with the Government of Alberta described in Note 4(A) of the Corporation's most recent annual consolidated financial statements, the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the Property, Plant, and Equipment ("PP&E") and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the six months ended June 30, 2017 increased in total by approximately $28 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

As a result of the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 3C for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the three months ended June 30, 2017 increased in total by approximately $4 million and the full year 2017 depreciation and amortization expense is expected to increase by approximately $15 million.

B. Future Accounting Changes

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

With respect to IFRS 9, the Corporation is in the process of completing its assessment of the classification and measurement portion of the standard. Activities to identify and calculate impacts from the impairment portion of the standard have commenced. In addition, the review of process and disclosure requirements have commenced. It is not yet possible to make a reliable estimate of the impact of IFRS 9 on the financial statements and disclosures. The Corporation's current estimate of the time and effort necessary to complete the implementation plan for IFRS 9 extends into late 2017.

With respect to IFRS 15, the Corporation is in the process of completing the accounting assessment of its revenue streams and underlying contracts with customers. In addition, the review of process and disclosure requirements have commenced. The majority of the Corporation's revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms. Commentary on implementation issues specific to the power and utilities industry is in the process of being discussed and issued by standard setters in the United States. Certain implementation commentary is expected to be relevant to the Corporation's long term arrangements. The Corporation's current estimate that the time and effort necessary to complete the Corporation's implementation plan for IFRS 15 will extend into late 2017. The Corporation anticipates finalizing a decision with respect to the transition method in late 2017. It is not yet possible to make a reliable estimate of the impact IFRS 15 will have on the financial statements and disclosures.

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

C. Comparative Figures

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

3. Significant Events

A. Kent Hills 3 Wind Project

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

This is an expansion project of the Corporation's existing Kent Hills wind project on approximately five to ten acres of Crown land, increasing the total operating capacity of the Kent Hills wind project to approximately 167 MW. As part of the regulatory process, the Corporation is submitting an Environmental Impact Assessment to the province of New Brunswick in the third quarter. If environmental approvals are received, the Corporation expects to begin the construction phase in the spring of 2018.

At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035.

B. Series C Preferred Share Conversion Results and Rate Reset

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

C. Transition to Clean Power in Alberta and Impairment Charge

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

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

Sundance Units 1 and 2

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

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

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

No change in estimated useful life or separate stand-alone impairment test arose for Sundance Unit 2, as mothballing the Unit maintains the Corporation's flexibility to operate the Unit beyond the expiry of the PPA to 2021.

D. Change in Credit Rating

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

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

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

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

E. Mississauga Cogeneration Facility NUG Contract

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

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in Ontario.

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

F. Wintering Hills Sale

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

G. Preferred Share Exchange

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

4. Net Other Operating Income

A. Alberta Off-Coal Agreement

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

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $39.7 million ($37.2 million, net to the Corporation), commencing Jan. 1, 2017 and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Accordingly, during the three and six months ended June 30, 2017, approximately $10 million and $20 million, respectively, was recognized in Net Other Operating Income in the Condensed Consolidated Statement of Earnings. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

5. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Interest on debt	**56**	54	**112**	111
Interest income	**(1)**	-	**(2)**	(1)
Capitalized interest	**(5)**	(4)	**(8)**	(7)
Loss on redemption of bonds	**-**	1	**-**	1
Interest on finance lease obligations	**1**	1	**2**	2
Other[(1)]	**3**	5	**7**	9
Accretion of provisions	**5**	5	**10**	11
Net interest expense	**59**	62	**121**	126

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

6. Income Taxes

The components of income tax expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Current income tax expense	**6**	6	**12**	11
Deferred income tax recovery related to the origination and reversal of temporary differences	**(4)**	(10)	**(21)**	(11)
Deferred income tax expense related to temporary difference on investment in subsidiary	**-**	3	**-**	3
Deferred income tax expense resulting from changes in tax rates or laws	**-**	-	**-**	1
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets(1)	**(21)**	(23)	**(27)**	(46)
Income tax recovery	**(19)**	(24)	**(36)**	(42)

(1) During the three and six months ended June 30, 2017, the Corporation reversed a previous writedown of deferred income tax assets of $21 million and $27 million, respectively. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. Recognized other comprehensive income during the period has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Current income tax expense	**6**	6	**12**	11
Deferred income tax recovery	**(25)**	(30)	**(48)**	(53)
Income tax recovery	**(19)**	(24)	**(36)**	(42)

7. Non-Controlling Interests

The Corporation's subsidiaries with significant non-controlling interests are TransAlta Renewables and TransAlta Cogeneration L.P.

The net earnings, distributions, and equity attributable to TransAlta Renewables' non-controlling interests include the 17 per cent non-controlling interest in the 150 MW Kent Hills wind farm located in New Brunswick.

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

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

(1) As the Class B shares issued to the Corporation on the sale of the Australian assets were determined to constitute financial liabilities of TransAlta Renewables and do not participate in earnings until commissioning of the South Hedland facility, they are excluded from the allocation of equity and earnings. See Note 16 Subsequent Events for further details.

Amounts attributable to non-controlling interests are as follows:

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Net earnings (loss)				
TransAlta Cogeneration L.P.	**2**	8	**22**	19
TransAlta Renewables	**10**	(4)	**22**	(18)
	12	4	**44**	1
Total comprehensive income (loss)				
TransAlta Cogeneration L.P.	**3**	16	**22**	30
TransAlta Renewables	**23**	(17)	**41**	(31)
	26	(1)	**63**	(1)
Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**30**	16	**56**	35
TransAlta Renewables	**21**	21	**42**	41
	51	37	**98**	76

As at	June 30, 2017	Dec. 31, 2016
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**268**	301
TransAlta Renewables	**856**	851
	1,124	1,152
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**40.2**	40.2

8. Financial Instruments

A. Financial Assets and Liabilities – Measurement

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

B. Fair Value of Financial Instruments

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

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

a. Level I

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

b. Level II

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

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

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

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

c. Level III

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

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

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

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

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is 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, 2017		Dec. 31, 2016	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	947	+151 -151	907	+75 -69
Long-term power sale - Alberta	(2)	+3 -3	(3)	+5 -5
Unit contingent power purchases	13	+2 -3	13	+2 -4
Structured products - Eastern U.S.	29	+8 -8	24	+8 -8
Others	6	+3 -3	6	+3 -3

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

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

For periods beyond June 2019, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per Megawatt hour ("MWh") used in determining the Level III base fair value at June 30, 2017 are US$23 - US$33 (Dec. 31, 2016 - US$27 - US$36). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2016 – US$5) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. The change in the US dollar against the Canadian dollar did not have a material impact on the base fair value this period.

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, 2017 are $67 - $82 (Dec. 31, 2016 - $68 - $93). The sensitivity analysis for both periods has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

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

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

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at June 30, 2017 are nil (Dec. 31, 2016 – nil) and 1.69 per cent to 2.76 per cent (Dec. 31, 2016 – 2.15 per cent to 3.62 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 0.52 per cent to 0.93 per cent (Dec. 31, 2016 – 0.75 per cent) and a change in volumetric discount rates of approximately 7.22 per cent to 9.93 per cent (Dec. 31, 2016 – 15.5 per cent), which approximate one standard deviation for each input.

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

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at June 30, 2017 are 75 per cent to 156 per cent and 71 per cent to 88 per cent (Dec. 31, 2016 – 66 per cent to 128 per cent and 65 per cent to 88 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 5 per cent (Dec. 31, 2016 – 5 per cent) and a change in non-standard shape factors of approximately 6 per cent (Dec. 31, 2016 – 9 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at June 30, 2017 are 21 per cent to 46 per cent and 70 per cent (Dec. 31, 2016 – 20 per cent to 54 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities and correlation of approximately 24 per cent (Dec. 31, 2016 – 10 per cent), respectively.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by Levels as at June 30, 2017 are as follows: Level I - $4 million net liability (Dec. 31, 2016 – nil), Level II - $11 million net liability (Dec. 31, 2016 - $14 million net liability), Level III - $807 million net asset (Dec. 31, 2016 – $758 million net asset).

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

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

	6 months ended June 30, 2017			6 months ended June 30, 2016		
	Hedge	Non-Hedge	Total	Hedge	Non-Hedge	Total
Opening balance	726	32	758	640	(98)	542
Changes attributable to:						
Market price changes on existing contracts	97	1	98	175	30	205
Market price changes on new contracts	-	6	6	-	4	4
Contracts settled	(25)	(2)	(27)	(20)	72	52
Change in foreign exchange rates	(27)	(1)	(28)	(65)	2	(63)
Net risk management assets at end of period	771	36	807	730	10	740
Additional Level III information:						
Gains recognized in OCI	70	-	70	110	-	110
Total gains included in earnings before income taxes	25	6	31	20	36	56
Unrealized gains included in earnings before income taxes relating to net assets held at period end	-	4	4	-	108	108

III. Other Risk Management Assets and Liabilities

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

Other risk management assets and liabilities with a total net asset fair value of $53 million as at June 30, 2017 (Dec. 31, 2016 - $176 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended June 30, 2017 are primarily attributable to the settlement of contracts.

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

IV. Other Financial Assets and Liabilities

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

	Fair value				Total carrying value
	Level I	Level II	Level III	Total	
Long-term debt - June 30, 2017	**-**	**3,829**	**-**	**3,829**	**3,738**
Long-term debt[1] - Dec. 31, 2016	-	4,271	-	4,271	4,221

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

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

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability.

C. Inception Gains and Losses

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

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Unamortized net gain at beginning of period	**143**	174	**148**	202
New inception gain (loss)	**(1)**	2	**4**	4
Change in foreign exchange rates	**(2)**	1	**(4)**	(11)
Amortization recorded in net earnings during the period	**(27)**	(20)	**(35)**	(38)
Unamortized net gain at end of period	**113**	157	**113**	157

9. Risk Management Activities

A. Net Risk Management Assets and Liabilities

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

As at June 30, 2017	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	96	-	-	96
Long-term	696	-	-	696
Net commodity risk management assets (liabilities)	792	-	-	792
Other				
Current	-	-	54	54
Long-term	-	-	(1)	(1)
Net other risk management assets	-	-	53	53
Total net risk management assets	792	-	53	845

As at Dec. 31, 2016	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	86	-	(16)	70
Long-term	683	-	(9)	674
Net commodity risk management assets (liabilities)	769	-	(25)	744
Other				
Current	105	-	8	113
Long-term	59	3	1	63
Net other risk management assets	164	3	9	176
Total net risk management assets (liabilities)	933	3	(16)	920

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments, which are also more fully discussed in Note 14(b) of the Corporation's most recent annual consolidated financial statements.

I. Market Risk

a. Commodity Price Risk

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

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at June 30, 2017, associated with the Corporation's proprietary trading activities was $3 million (Dec. 31, 2016 - $2 million).

ii. Commodity Price Risk - Generation

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

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes.

VaR at June 30, 2017, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $20 million (Dec. 31, 2016 - $19 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at June 30, 2017, associated with these transactions was $5 million (Dec. 31, 2016 - $7 million).

b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the U.S. dollar, and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers. Further discussion on Currency Rate Risk can be found in Note 14(B)(I)(c) of the Corporation's most recent annual consolidated financial statements.

II. Credit Risk

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

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at June 30, 2017:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	91	9	100	671
Long-term finance lease receivables[2]	34	66	100	672
Risk management assets[1]	99	1	100	966
Total				2,309

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The Corporation has one non-investment grade customer whose outstanding balance accounted for $437 million (Dec. 31, 2016 - $445 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, 2017, was $19 million (Dec. 31, 2016 - $14 million).

The Corporation had two investment grade customers whose outstanding balance each accounted for greater than 10 per cent of accounts receivable outstanding. The Corporation has evaluated the risk of default related to these customers to be minimal.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. As at June 30, 2017, TransAlta maintains investment grade ratings from three credit rating agencies (See Note 16). TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

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

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Accounts payable and accrued liabilities	421	-	-	-	-	-	421
Long-term debt[1]	42	932	461	560	63	1,705	3,763
Commodity risk management assets	(60)	(78)	(93)	(82)	(97)	(382)	(792)
Other risk management (assets) liabilities	(5)	(52)	3	1	-	-	(53)
Finance lease obligations	9	13	10	8	6	19	65
Interest on long-term debt and finance lease obligations[2]	121	174	144	116	93	734	1,382
Dividends payable	26	-	-	-	-	-	26
Total	554	989	525	603	65	2,076	4,812

(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, 2017, the Corporation had posted collateral of $106 million (Dec. 31, 2016 - $116 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $61 million (Dec. 31, 2016 - $49 million) of collateral to its counterparties.

10. Property, Plant, and Equipment

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

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
As at Dec. 31, 2016	95	2,664	498	2,290	606	407	264	6,824
Additions	-	-	-	-	-	154	3	157
Additions - finance lease	-	1	-	-	-	-	-	1
Asset impairment charges *(Note 3)*	-	(20)	-	-	-	-	-	(20)
Depreciation	-	(167)	(29)	(62)	(35)	-	(10)	(303)
Revisions and additions to decommissioning and restoration costs	-	73	5	6	(6)	-	-	78
Retirement of assets and disposals	-	(5)	-	-	(2)	-	-	(7)
Change in foreign exchange rates	(1)	(12)	5	(9)	(2)	5	-	(14)
Transfers[2]	2	61	26	8	8	(99)	(18)	(12)
As at June 30, 2017	96	2,595	505	2,233	569	467	239	6,704

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

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

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at	June 30, 2017			Dec. 31, 2016		
	Carrying value	Face value	Interest(1)	Carrying value	Face value	Interest(1)
Credit facilities(2)	100	100	3.3%	-	-	-
Debentures	1,046	1,051	6.0%	1,045	1,051	6.0%
Senior notes(2)	1,551	1,562	6.0%	2,151	2,158	5.0%
Non-recourse(3)	992	1,001	4.5%	1,038	1,048	4.5%
Other(4)	49	49	9.1%	54	54	9.2%
	3,738	3,763		4,288	4,311	
Finance lease obligations	65			73		
	3,803			4,361		
Less: current portion of long-term debt	(928)			(623)		
Less: current portion of finance lease obligations	(15)			(16)		
Total current long-term debt and finance lease obligations	(943)			(639)		
Total credit facilities, long-term debt, and finance lease obligations	2,860			3,722		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) U.S. face value at June 30, 2017 - US$1.2 billion (Dec. 31, 2016 - US$1.6 billion).
(3) Includes US$49 million at June 30, 2017 (Dec. 31, 2016 - US$53 million).
(4) Includes US$26 million at June 30, 2017 (Dec. 31, 2016 - US$29 million) of tax equity financing.

During the second quarter of 2017, the Corporation repaid a US$400 million US Senior Note on maturity. The repayment was hedged with a cross currency swap. The maturity value of the bond was $434 million.

Of the $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities (see Note 16 Subsequent Events for further details), $1.3 billion (Dec. 31, 2016 - $1.4 billion) is not drawn. At June 30, 2017, the $0.7 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of $0.1 billion (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, TransAlta also has $50 million of available cash and cash equivalents. See Note 16 for further details on TransAlta Renewables' announced syndicated credit facility.

The total outstanding letters of credit as at June 30, 2017 was $556 million (Dec. 31, 2016 - $566 million) with no (Dec. 31, 2016 - 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, 2017, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of $192 million (Dec. 31, 2016 - $193 million) issued by the Corporation's subsidiary, Canadian Hydro Developers, Inc. ("CHD"), include restrictive covenants requiring the cash proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond and Mass Solar bonds are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the second quarter. However, funds in these entities that have accumulated since the second quarter test, will remain there until the next debt service coverage ratio can be calculated in the third quarter of 2017. At June 30, 2017, $20 million (Dec. 31, 2016 - $24 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at June 30, 2017. As at June 30, 2017, $1 million of cash was on deposit for certain reserves and was not available for general use.

C. Security

Non-recourse debts of $616 million (Dec. 31, 2016 - $644 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of $930 million at June 30, 2017 (Dec. 31, 2016 - $956 million). At June 30, 2017, a non-recourse bond of approximately $184 million (Dec. 31, 2016 - $201 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

12. Common Shares

A. Issued and Outstanding

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

	3 months ended June 30				6 months ended June 30			
	2017		2016		2017		2016	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount	**Common shares** *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**287.9**	**3,095**	287.9	3,095	**287.9**	**3,095**	284.0	3,077
Issued under the dividend reinvestment and optional common share purchase plan	**-**	**-**	-	-	**-**	**-**	3.9	18
	287.9	**3,095**	287.9	3,095	**287.9**	**3,095**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**-**	**(1)**	-	(2)	**-**	**(1)**	-	(2)
Issued and outstanding, end of period	**287.9**	**3,094**	287.9	3,093	**287.9**	**3,094**	287.9	3,093

B. Dividends

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

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

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

C. Stock Options

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

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

13. Preferred Shares

A. Issued and Outstanding

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

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

B. Dividends

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

		3 months ended June 30		6 months ended June 30	
	Quarterly amounts	**2017**	2016	**2017**(1)	2016
Series	per share	**Total**	Total	**Total**	Total
A	0.16931(2)	**2**	1	**2**	5
B	0.15645(3)	**-**	1	**-**	1
C	0.2875(4)	**3**	3	**3**	6
E	0.3125	**3**	3	**3**	6
G	0.33125	**2**	2	**2**	4
Total for the period		**10**	10	**10**	22

(1) No dividends were declared in the first quarter, as on Dec. 19, 2016, the quarterly dividend related to the period covering the first quarter of 2017 was declared.
(2) Dividends on Class A shares for the first quarter of 2016 were $0.2875 per share.
(3) Series B shares pay quarterly dividends at a floating rate based on the 90 day Government of Canada Treasury Bill rate, plus 2.03 per cent. The Series B shares were issued on March 17, 2016.
(4) The quarterly dividend rate for the Series C Preferred shares for the five-year period from and including June 30, 2017 to, but excluding June 30, 2022, will be $0.25169 following the rate reset of the Series C Preferred Shares effective June 30, 2017.

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

On July 18, 2017, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.16125 per share on the Series B preferred shares, $0.25169 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, 2017.

14. Commitments and Contingencies

A. Commitments

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

B. Contingencies

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

I. Line Loss Rule Proceeding

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

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

15. Segment Disclosures

A. Reported Segment Earnings (Loss)

I. Earnings Information

3 months ended June 30, 2017	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	248	59	51	28	59	40	18	-	503
Fuel and purchased power	141	15	15	4	3	2	-	-	180
Gross margin	107	44	36	24	56	38	18	-	323
Operations, maintenance, and administration	47	11	14	6	12	9	6	22	127
Depreciation and amortization	77	16	9	7	28	9	1	7	154
Asset impairment charge	20	-	-	-	-	-	-	-	20
Taxes, other than income taxes	4	1	-	-	2	1	-	-	8
Net other operating income	(10)	-	-	-	-	-	-	-	(10)
Operating income (loss)	(31)	16	13	11	14	19	11	(29)	24
Finance lease income	-	-	3	13	-	-	-	-	16
Net interest expense									(59)
Foreign exchange gain									2
Other income									2
Loss before income taxes									(15)

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)
Loss before income taxes									(4)

6 months ended June 30, 2017	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	498	147	153	54	146	64	19	-	1,081
Fuel and purchased power	280	79	54	6	8	3	-	-	430
Gross margin	218	68	99	48	138	61	19	-	651
Operations, maintenance, and administration	91	24	26	13	24	17	11	46	252
Depreciation and amortization	147	31	18	14	55	17	1	14	297
Asset impairment charge	20	-	-	-	-	-	-	-	20
Taxes, other than income taxes	7	2	1	-	4	2	-	-	16
Net other operating income	(20)	-	-	-	-	-	-	-	(20)
Operating income (loss)	(27)	11	54	21	55	25	7	(60)	86
Finance lease income	-	-	6	26	-	-	-	-	32
Net interest expense									(121)
Foreign exchange gain									1
Other income									2
Earnings before income taxes									-

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

Included in revenues of the Wind and Solar Segment for the three and six months ended June 30, 2017 are $4 million (2016 - $4 million) and $10 million (2016 - $11 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

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

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

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

	3 months ended June 30		6 months ended June 30	
	2017	2016	**2017**	2016
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings (Loss)	**154**	147	**297**	269
Depreciation included in fuel and purchased power	**19**	14	**36**	28
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**173**	161	**333**	297

16. Subsequent Events

A. Commissioning of South Hedland and Conversion of Class B Shares

The South Hedland facility achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent.

On Aug. 1, 2017, Fortescue Metals Group Ltd. ("FMG") issued a news release indicating that it had notified the Corporation that in its view the South Hedland Facility has not yet satisfied the requisite performance criteria under the South Hedland power purchase agreement between FMG and the Corporation.

B. Termination of Solomon Power Purchase Agreement

On Aug. 1, 2017, the Corporation received notice that FMG intends to repurchase the Solomon Power facility from TEC Pipe Pty Ltd., a wholly-owned subsidiary of the Corporation, for approximately US$335 million. FMG is expected to complete its acquisition of the Solomon Power Station in November 2017.

C. TransAlta Renewables Credit Facility

On July 24, 2017, TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The agreement is fully committed for four years, expiring in 2021. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the new credit agreement, the existing $350 million credit facility currently provided by TransAlta was cancelled. The Corporation's consolidated liquidity will remain unchanged, as the Corporation's credit facility decreased by $500 million to $1 billion in total, while TransAlta Renewables' facility increased to a total of $500 million.

D. Balancing Pool PPA Termination Consultation

On July 4, 2017, the Balancing Pool announced its intention to consult with customer representatives regarding the termination of the Alberta PPAs that it holds for Sundance A, Sundance B and Sundance C (the "Sundance PPAs"). It also stated that it considered the termination of the Sundance PPAs to be reasonable.

Under Section 97 of the Electric Utilities Act (Alberta), the Balancing Pool may terminate the PPAs if it:

- Consults with representatives of customers and the Minister of Energy about the reasonableness of the termination;
- Gives to the owner of the generating unit to which the PPA applies 6 months' notice, or any shorter period agreed to by the owner, of its intention to terminate, and;
- Pays the owner or ensures that the owner receives an amount equal to the remaining closing net book value of the generating unit, determined in accordance with the PPA, as if the generating unit had been destroyed, less any insurance proceeds.

The Corporation has 3,770 MW of gross capacity under PPAs, including hydro, representing approximately 23 per cent of the generation capacity in Alberta. If, after meeting the requirements, the Balancing Pool chooses to terminate the Sundance B and C PPAs, the Corporation expects to receive approximately $231 million in payment for the net book value of the assets. Proceeds from any termination would be used to reduce outstanding debt, fund growth opportunities, and replace current gross margin from the existing PPAs. The Sundance A PPA expires at the end of 2017 and, as such, it was not included in the Balancing Pool's initial PPA termination considerations.

Exhibit 1

(Unaudited)

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

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the three months ended June 30, 2017:

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

1.45 times [(1)]

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