TRANSALTA CORPORATION
THIRD QUARTER REPORT FOR 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2014 and 2013, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2013 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation', and 'TransAlta' refer to TransAlta Corporation and its subsidiaries. The condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standard ("IFRS") IAS 34 *Interim Financial Reporting*. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 29, 2014. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading, and Corporate. For this MD&A, we have further split what is reported as our Generation business segment into the various fuel types to provide additional information to our readers. In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Condensed Consolidated Statements of Earnings (Loss) and Condensed Consolidated Statements of Financial Position items. While individual line items in the Condensed Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of these items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive Income (Loss) ("AOCI") in the equity section of the Condensed Consolidated Statements of Financial Position.

NON-IFRS MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of these 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 Funds from Operations and Free Cash Flow, and Earnings and Other Measures on a Comparable Basis, sections of this MD&A for additional information.

HIGHLIGHTS

Consolidated Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Revenues	**639**	623	**1,905**	1,705
Comparable EBITDA[1]	**212**	266	**735**	781
Net earnings (loss) attributable to common shareholders	**(6)**	(9)	**(7)**	(5)
Comparable net earnings (loss) attributable to common shareholders[1]	**(13)**	39	**22**	80
Funds from operations[1]	**145**	174	**537**	551
Cash flow from operating activities	**216**	253	**546**	601
Free cash flow[1]	**33**	64	**191**	235
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.03)**	(0.03)	**(0.03)**	(0.02)
Comparable net earnings (loss) per share[1]	**(0.05)**	0.15	**0.08**	0.31
Funds from operations per share[1]	**0.53**	0.65	**1.97**	2.10
Free cash flow per share[1]	**0.12**	0.24	**0.70**	0.90
Dividends paid per common share	**0.18**	0.29	**0.65**	0.87

As at	**Sept. 30, 2014**	Dec. 31, 2013[2]
Total assets	**9,568**	9,624
Total long-term liabilities	**4,613**	5,348

Financial Highlights

- Comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA") for the third quarter and year-to-date periods in 2014 totalled $212 million and $735 million, respectively, with strong availability throughout our generation portfolio and continued improved operational performance at Canadian Coal. Third quarter and year-to-date comparable EBITDA decreased $54 million and $46 million, respectively, compared to the same periods in 2013, primarily due to lower prices in Alberta which impacted our assets in the province. Prices in Alberta averaged $56 per megawatt hour ("MWh") during the nine months ended Sept. 30, 2014, compared to $91 per MWh in the same period in 2013. Hydro assets were further impacted by reduced price volatility and lower water resource. Our strategy of being highly contracted and high availability in Canadian Coal generally limited the impacts of lower prices in Alberta. The third quarter was also impacted by lower trading margins.
- Funds from operations ("FFO") for the three and nine months ended Sept. 30, 2014 decreased $29 million and $14 million, respectively, compared to the same periods in 2013, primarily due to lower comparable EBITDA, partially offset by higher realized gains from risk management activities and lower current income tax expense.
- These results were in line with our expectations. However, subsequent to Sept. 30, 2014, we have observed weaker than expected prices for the fourth quarter, which impact primarily our Alberta wind and hydro assets. Accordingly, our forecasts for the year are tracking to the lower end of previously disclosed comparable EBITDA and FFO guidance, and expected ranges have been revised accordingly. Revised expected comparable EBITDA for 2014 is between $1,005 million and $1,025 million, and revised expected FFO is between $735 million and $755 million.

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(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Funds from Operations and Free Cash Flow 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) After giving effect to the reclassification described in the Current Accounting Changes section of this MD&A.

- Third quarter comparable net loss attributable to common shareholders was $13 million ($0.05 net loss per share) and year-to-date comparable net earnings attributable to common shareholders was $22 million ($0.08 net earnings per share), down from comparable net earnings of $39 million ($0.15 net earnings per share) and $80 million ($0.31 net earnings per share), respectively, due to the decrease in comparable EBITDA and higher non-controlling interests, partially offset by lower income tax expense.
- Reported net loss attributable to common shareholders was $6 million for the third quarter ($0.03 net loss per share) and $7 million year-to-date ($0.03 net loss per share), compared to a net loss of $9 million ($0.03 net loss per share) and $5 million ($0.02 net loss per share) for the same periods in 2013. The difference between comparable and reported net earnings is due to increases in the fair value of future period economic hedges at U.S. Coal, and a larger deferred income tax writedown in 2013. The change in the year-to-date reported net loss was also impacted by a one-time loss on assumption of pension obligations in the prior period.

Strategic Initiative Highlights

During the quarter we continued to make significant progress to grow our portfolio of highly contracted assets, improve our operating performance, and strengthen our financial condition.

- Entered into agreements to build and operate a 150 megawatt ("MW") combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 to build. The fully contracted power station is expected to be commissioned and delivering power to customers in the first half of 2017. We expect to receive our permits before the end of 2014, and begin construction during the first quarter of 2015.
- Continued construction with our joint venture partner of an AUD$178 million natural gas pipeline to our Solomon power station. We hold a 43 per cent interest in the joint venture. The project is on schedule and within budget, with expected commencement of commercial operations in early 2015.
- Successfully completed an offering of preferred shares for gross proceeds of $165 million. Proceeds from this transaction will provide flexibility to repay debt maturing early in 2015.
- Continued executing our hydro life extension plan, sustaining our advantage as the first hydro power producer in Alberta.

Earlier this year we completed the following transactions:

- Completed the sale of our 50 per cent ownership of CE Generation LLC ("CE Gen"), the Blackrock Development Project ("Blackrock"), and CalEnergy, LLC ("CalEnergy") for net proceeds of U.S.$188.5 million.
- Completed a secondary offering of TransAlta Renewables Inc. ("TransAlta Renewables") shares for proceeds of approximately $129 million, net of offering costs.
- Successfully completed an offering of U.S.$400 million of senior notes, due in June 2017.

Operational Results

Comparable EBITDA is as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Availability (%)[1]	**92.0**	85.9	**88.6**	83.1
Adjusted availability (%)[1,2]	**92.0**	85.9	**89.6**	86.4
Production (GWh)[1]	**11,445**	11,088	**32,795**	29,842
Comparable EBITDA				
Generation Segment				
Canadian Coal	**91**	95	**268**	239
U.S. Coal	**12**	20	**43**	52
Gas	**77**	75	**228**	246
Wind	**26**	25	**121**	121
Hydro	**26**	50	**65**	127
Total Generation Segment	**232**	265	**725**	785
Energy Trading Segment	**(3)**	17	**50**	41
Corporate Segment	**(17)**	(16)	**(40)**	(45)
Total comparable EBITDA	**212**	266	**735**	781

- Canadian Coal: Comparable EBITDA decreased slightly to $91 million in the third quarter and increased to $268 million year-to-date, compared to $95 million and $239 million, respectively, for the same periods in 2013. The increase in year-to-date comparable EBITDA is primarily driven by increased availability, from 78.2 per cent during the period in 2013 to 87.6 per cent in 2014. We have also been able to decrease fuel costs per tonne through greater efficiency and productivity. In the third quarter of 2014, the benefits of these improvements have been offset by lower Alberta prices. Our contract profile in Alberta as well as our hedging strategy significantly mitigates the $35 per MWh market price reduction year over year. Sundance Units 1 and 2, which returned to service a year ago, have been performing as planned.
- U.S. Coal: Comparable EBITDA was $12 million in the third quarter and $43 million year-to-date, compared to $20 million and $52 million, respectively, for the same periods in 2013, primarily due to lower volumes of higher-priced hedges. In the third quarter of 2014, we also incurred higher costs than in the same period in 2013 to purchase power during periods of curtailment. In order to mitigate coal supply risks during the winter months, coal has been stockpiled in anticipation of increased rail congestion into 2015.
- Gas: Comparable EBITDA was $77 million in the third quarter and $228 million year-to-date, compared to $75 million and $246 million, respectively, for the same periods in 2013. The decrease in year-to-date comparable EBITDA is primarily due to lower Alberta prices impacting results from the Poplar Creek facility in the second quarter and the effects of the new contract at Ottawa. Increases in third quarter comparable EBITDA are primarily due to increases in fair value of forward purchase and physical gas volumes in Ontario, which is offset by losses in the Energy Trading Segment.
- Wind: Comparable EBITDA was consistent in the third quarter and year-to-date with the same periods in 2013. Production from our Wyoming facility has offset the effects of lower Alberta prices. We have also achieved higher availability through targeted maintenance spend.

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(1) Availability and production includes all generating assets (generation operations, finance leases, and equity investments).

(2) Adjusted for economic dispatching at Centralia Thermal.

- Hydro: Comparable EBITDA was $26 million in the third quarter and $65 million year-to-date, compared to $50 million and $127 million, respectively, for the same periods in 2013. In 2013, the combination of abundant water resource and high prices had lifted comparable EBITDA. We continue to maintain ample water resource to capture pricing opportunities as they arise.
- Energy Trading Segment: Energy Trading generated a loss of $3 million in the third quarter, down $20 million compared to the third quarter of 2013. Lower commodity price volatility in Alberta and the western U.S. impacted Energy Trading's ability to generate gross margin. In addition, timing differences related to supplying gas to our Eastern assets negatively impacted our gross margin in the third quarter, which is offset by gains in the Gas results. Year-to-date comparable EBITDA in 2014 was $50 million, up $9 million from $41 million in the same period in 2013 as a result of our ability to optimize our energy marketing assets during extraordinarily volatile market conditions caused by extreme weather events in the northeast during the first quarter of 2014.
- Corporate Segment: Our Corporate Segment incurred similar costs in the third quarter of 2014 of $17 million compared $16 million in 2013. The Corporate Segment incurred costs of $40 million in year-to-date 2014 compared to $45 million in the same period in 2013. The lower costs resulted from a change in the way in which certain overhead cost allocations are made within the organization, partially offset by higher incentive-based compensation.

AVAILABILITY & PRODUCTION

Availability for the three and nine months ended Sept. 30, 2014 increased compared to the same periods in 2013, primarily due to lower unplanned outages at Canadian Coal.

Production for the three months ended Sept. 30, 2014 increased 357 gigawatt hours ("GWh") compared to the same period in 2013, primarily due to Sundance Units 1 and 2 returning to service and lower unplanned outages at Canadian Coal, partially offset by higher contract curtailments in Alberta.

For the nine months ended Sept. 30, 2014, production increased 2,953 GWh compared to the same period in 2013, primarily due to Sundance Units 1 and 2 returning to service, lower unplanned outages at Canadian Coal, lower economic dispatching at Centralia Thermal, and the acquisition of Wyoming Wind, partially offset by higher contract curtailments.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

Presenting non-IFRS measures such as FFO, free cash flow, funds from operations per share, and free cash flow per share from period to period provides management, and investors, with a proxy for the amount of cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods.

FFO per share and free cash flow per share are calculated as follows using the weighted average number of common shares outstanding during the period:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Cash flow from operating activities	**216**	253	**546**	601
Impacts associated with California claim	**-**	-	**33**	-
Payment of restructuring costs	**-**	1	**-**	5
Non-comparable insurance proceeds	**-**	-	**(6)**	-
Timing of payments related to assumption of pension obligations	**-**	(7)	**-**	-
Decrease in finance lease receivable	**1**	-	**2**	1
Flood-related maintenance costs	**4**	4	**12**	5
Change in non-cash operating working capital balances	**(76)**	(77)	**(50)**	(61)
FFO	**145**	174	**537**	551
Deduct:				
Sustaining capital expenditures	**(84)**	(93)	**(255)**	(245)
Dividends paid on preferred shares	**(9)**	(9)	**(28)**	(28)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(8)	**(63)**	(43)
Free cash flow	**33**	64	**191**	235
Weighted average number of common shares outstanding in the period	**273**	266	**272**	262
FFO per share	**0.53**	0.65	**1.97**	2.10
Free cash flow per share	**0.12**	0.24	**0.70**	0.90

A reconciliation of comparable EBITDA to FFO is as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Comparable EBITDA	**212**	266	**735**	781
Realized gains (losses) from risk management activities	**6**	(26)	**16**	(16)
Interest expense	**(59)**	(61)	**(178)**	(177)
Provisions	**(4)**	10	**-**	10
Current income tax expense	**(7)**	(10)	**(24)**	(36)
Realized foreign exchange gain (loss)	**(4)**	(2)	**(3)**	3
Decommissioning and restoration costs settled	**(4)**	(6)	**(11)**	(19)
Reversal of restructuring charges	**-**	1	**-**	3
Payment of restructuring costs	**-**	1	**-**	5
Timing of payments related to assumption of pension obligations	**-**	(7)	**-**	-
Other non-cash items	**5**	8	**2**	(3)
FFO	**145**	174	**537**	551

FFO for the three months ended Sept. 30, 2014 decreased $29 million compared to the same period in 2013, to $145 million, primarily due to lower comparable EBITDA. For the nine months ended Sept. 30, 2014, FFO decreased $14 million compared to the same period in 2013, to $537 million, primarily due to lower comparable EBITDA, partially offset by lower current income tax expense. Cash interest was consistent for the three and nine month periods in 2014 and 2013.

Free cash flow for the three months ended Sept. 30, 2014 decreased $31 million compared to the same period in 2013 primarily due to the decrease in FFO.

For the nine months ended Sept. 30, 2014, free cash flow decreased $44 million compared to the same period in 2013, to $191 million, primarily due to reduced FFO and higher distributions paid to our subsidiaries' non-controlling interests as a result of the reduction of our interest in TransAlta Renewables and improved performance at TransAlta Cogeneration L.P. ("TA Cogen").

SIGNIFICANT EVENTS

South Hedland Power Project

On July 28, 2014, we announced that we had agreed to build, own, and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia. The project is estimated to cost approximately AUD$570 million to build, including the cost of acquiring existing equipment from Horizon Power. The development has been fully contracted under 25-year Power Purchase Agreements with Horizon Power, a state owned utility company, and The Pilbara Infrastructure Pty Ltd., a wholly owned subsidiary of Fortescue, a mining company. The project may be expanded to accommodate additional customers at later dates. The power station will supply Horizon Power's customers in the Pilbara region as well as Fortescue's port operations. IHI Engineering Australia has been selected as the contractor to construct the power station. Relevant work and environmental permits are expected to be received in the fourth quarter of 2014. Teams are preparing for site mobilization. Construction is expected to begin in early 2015 and the power station is expected to be commissioned and delivering power to customers in the first half of 2017.

Australia Natural Gas Pipeline

On Jan. 15, 2014, we announced the formation of an unincorporated joint venture named Fortescue River Gas Pipeline Joint Venture to build, own, and operate an AUD$178 million, 270 kilometer natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station. Usage of the pipeline has been contracted with our Solomon customer under a 20-year agreement. We hold a 43 per cent interest in the joint venture through a wholly owned subsidiary. The project is on schedule and within budget. Construction of the pipeline has begun from both east and west ends, with multiple construction crews working at any one time. As at Sept. 30, 2014, over 40 kilometers of pipe had been welded. In addition to our portion of the pipeline cost, AUD$14 million in plant retrofitting costs are being incurred to allow the Solomon power station to burn gas instead of diesel, which will provide a return over time through increased lease payments.

Sale of Preferred Shares

On Aug. 15, 2014, we completed a public offering of 6.6 million Series G 5.3 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $165 million. The proceeds from the offering are being used for general corporate purposes, including the repayment of debt coming due in January 2015.

Sale of CE Gen, Blackrock, and CalEnergy

On June 12, 2014, we completed the previously announced sale of our 50 per cent interest in CE Gen, Blackrock, and CalEnergy to MidAmerican Renewables for gross proceeds of U.S.$200.5 million. The net proceeds were U.S.$188.5 million, after consideration of an equity contribution made by us to CE Gen in May 2014. As a result of the sale, we recognized a pre-tax gain of $1 million in second quarter earnings.

We expect the sale of our 50 per cent interest in the Wailuku Holding Company, LLC ("Wailuku"), announced in February 2014, to close in December 2014.

Secondary Offering of TransAlta Renewables Shares

On April 29, 2014, we completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. As a result of the offering, we received gross proceeds of approximately $136 million (net proceeds of approximately $129 million after issuance costs). The net proceeds from the offering were used to reduce indebtedness, to fund growth, and for general corporate purposes. Following completion of the offering, we own approximately 70.3 per cent of the common shares of TransAlta Renewables.

Fort McMurray Transmission Project

On Jan. 17, 2014, we announced that our strategic partnership with MidAmerican Transmission, TAMA Transmission LP ("TAMA Transmission"), which was formed on May 9, 2013, successfully qualified to participate as a proponent in the Fort McMurray West 500 kilovolt Transmission Project. The Alberta Electric System Operator ("AESO") announced its selection of a short-list of companies, identifying TAMA Transmission as a participant in the next stage of its competitive process for the project. The AESO has indicated that it intends to select the preferred proponent in December 2014.

California Claim

On May 30, 2014, we announced that our settlement with California utilities, the California Attorney General and certain other parties ("California Parties") to resolve claims related to the 2000 - 2001 power crisis in the State of California had been approved by the U.S. Federal Energy Regulatory Commission. The settlement provides for the payment by us of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to us from accounts receivable. The first payment of U.S.$26 million was paid in June 2014 and the second is expected to be made in 2015. During the fourth quarter of 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to earnings of approximately $56 million. An additional pre-tax charge to 2014 second quarter earnings of $5 million arose as a result of the final settlement.

Proceedings before the Alberta Utilities Commission

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the Alberta Utilities Commission (the "AUC") alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. TransAlta has denied the MSA's allegations in their entirety. The MSA's application is presently before the AUC. The hearing in relation to the application is currently set to proceed in December 2014.

Senior Notes Offering

On June 3, 2014, we completed an offering of U.S.$400 million of senior notes, due in June 2017, that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

Sundance Unit 6 Agreement

On Feb. 19, 2014, we reached an agreement with the Power Purchase Arrangement ("PPA") Buyer related to the dispute on Sundance Unit 6. There were no material impacts to the financial statements as a result of the agreement.

Board of Directors Appointments

During the third quarter of 2014, we announced that Mr. P. Thomas Jenkins, OC, CD and Mr. John. P. Dielwart had been appointed to our Board of Directors, effective Sept. 1 and Oct. 1, 2014, respectively. The appointments are the result of our ongoing process of evaluating the skills and composition of the Board, planning for succession, and aligning the skills of the Board with the strategic direction of the Corporation.

Executive Leadership Team Appointments

On March 18, 2014, we announced three senior leadership appointments that will enhance our objectives of operational excellence from the base business and growth. Brett Gellner was appointed to the role of Chief Investment Officer, responsible for leading all growth aspects of the Corporation. Donald Tremblay joined TransAlta as Chief Financial Officer, effective March 31, 2014, and on July 3, 2014, Wayne Collins joined TransAlta as Executive Vice President, Coal and Mining Operations.

BUSINESS ENVIRONMENT

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Western U.S., and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity and natural gas upon our financial results, refer to our 2013 Annual MD&A.

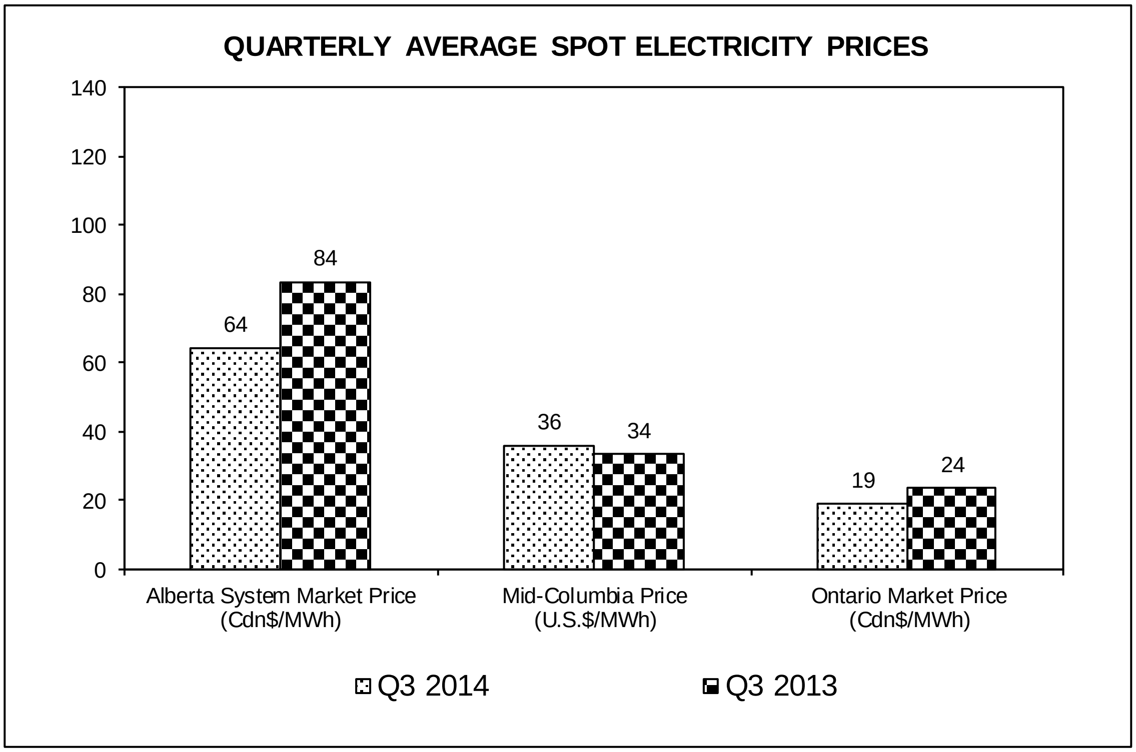
Contracted Cash Flows

During the third quarter of 2014, approximately 90 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also entered into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years. The average prices of these contracts for the balance of 2014 are approximately $55 per MWh in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

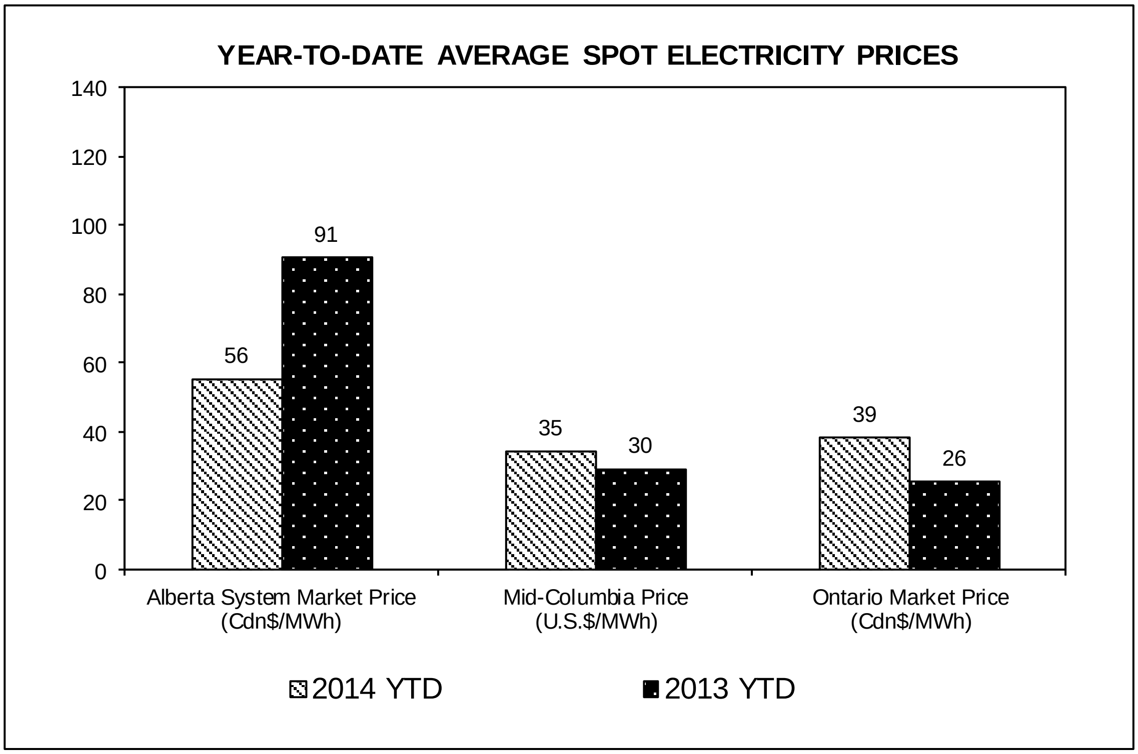
Electricity Prices

Please refer to the Business Environment section of our 2013 Annual MD&A for a full discussion of the spot electricity market and the impact of electricity prices on our business, as well as our strategy to hedge our risks associated with changes in these prices.

The average spot electricity prices for the three and nine months ended Sept. 30, 2014 and 2013 in our three major markets are shown in the following graphs:



For the three months ended Sept. 30, 2014, average spot prices in Alberta decreased compared to the same period in 2013, primarily due to an increase in supply. Average prices in the Pacific Northwest were consistent with the prior period as increased hydro flows and nuclear availability were offset by higher natural gas prices. Average spot prices in Ontario in the current quarter decreased due to lower demand, as well as increased hydro and renewable generation.



For the nine months ended Sept. 30, 2014, average spot prices in Alberta decreased significantly compared to the same period in 2013, primarily due to an increase in supply. In the Pacific Northwest, average spot prices increased due to higher natural gas prices, particularly in February, partially offset by higher hydro and nuclear production. Average spot prices in Ontario for the nine months ended Sept. 30, 2014 increased compared to the same period in 2013 due to extreme cold weather across the entire northeast during the first quarter, which led to higher natural gas prices and increased demand.

Over the balance of 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle lower than in 2013. Market prices in December 2013 increased as a result of significant cold weather. In Ontario, prices for the balance of the year are expected to be lower than 2013 despite higher natural gas prices due to fewer nuclear unit outages and increased wind capacity compared to 2013. While we did account for lower pricing in our guidance, recent market conditions have been weaker than anticipated and we believe these weak conditions could be sustained through the end of the year.

DISCUSSION OF SEGMENTED RESULTS

We have three business segments: Generation, Energy Trading, and Corporate.

Generation: *Owns and operates hydro, wind, natural gas-fired and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Electricity sales generated by our Commercial and Industrial group are assumed to be sourced from TransAlta's production and have been included in the Generation Segment on a net basis.*

The full capacity of the facilities in which we have a share of ownership is 10,144 MW(1)(2). At Sept. 30, 2014, our generating assets had 9,092 MW(1)(2) of gross generating capacity in operation (8,381 MW(1)(2) net ownership interest). The following information excludes assets that were accounted for using the equity method, which are discussed separately within this discussion of the Generation Segment.

The results of the Generation Segment are as follows:

	3 months ended Sept. 30, 2014			3 months ended Sept. 30, 2013(3)		
	Reported	**Comparable adjustments and reclassifications(4)**	**Comparable total**	Reported	Comparable adjustments and reclassifications(4)	Comparable total
Availability (%)(5)	**92.0**	**-**	**92.0**	85.7	-	85.7
Production (GWh)(5)	**11,445**	**-**	**11,445**	10,710	-	10,710
Gross installed capacity (MW)(1), (5)	**9,092**	**-**	**9,092**	8,668	-	8,668
Net installed capacity (MW)(1), (5)	**8,381**	**-**	**8,381**	8,073	-	8,073
Revenues	**636**	**(22)**	**614**	601	22	623
Fuel and purchased power	**277**	**(13)**	**264**	265	(16)	249
Gross margin	**359**	**(9)**	**350**	336	38	374
Operations, maintenance, and administration	**113**	**(4)**	**109**	103	(4)	99
Asset impairment reversals	**(1)**	**1**	**-**	(18)	18	-
Restructuring provision	**-**	**-**	**-**	(1)	1	-
Taxes, other than income taxes	**6**	**-**	**6**	7	-	7
Gain on sale of assets	**-**	**-**	**-**	-	(1)	(1)
Intersegment cost allocation	**3**	**-**	**3**	4	-	4
EBITDA	**238**	**(6)**	**232**	241	24	265
Depreciation and amortization	**128**	**13**	**141**	118	17	135
Decrease in finance lease receivable	**-**	**1**	**1**	-	-	-
Operating income	**110**	**(20)**	**90**	123	7	130

(1) We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated. Gross capacity reflects the basis of consolidation of underlying assets, while net capacity deducts capacity attributable to non-controlling interests in these assets.

(2) The Centralia gas plant is currently not in operation. We are currently assessing the generation needs of the region and the financial feasibility of bringing the plant back into operation.

(3) Refer to the Current Accounting Changes section of this MD&A for a description of prior period restatements.

(4) 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.

(5) Availability, production, and installed capacity include assets under generation operations and finance leases.

	9 months ended Sept. 30, 2014			9 months ended Sept. 30, 2013[1]		
	Reported	**Comparable adjustments and reclassifications[2]**	**Comparable total**	Reported	Comparable adjustments and reclassifications[2]	Comparable total
Availability (%)[3]	**88.5**	**-**	**88.5**	82.7		82.7
Adjusted availability (%)[3, 4]	**89.6**	**-**	**89.6**	86.1	-	86.1
Production (GWh)[3]	**32,481**	**-**	**32,481**	28,678	-	28,678
Gross installed capacity (MW)[2, 5]	**9,092**	**-**	**9,092**	8,668	-	8,668
Net installed capacity (MW)[2, 5]	**8,381**	**-**	**8,381**	8,073	-	8,073
Revenues	**1,829**	**31**	**1,860**	1,652	95	1,747
Fuel and purchased power	**824**	**(41)**	**783**	669	(42)	627
Gross margin	**1,005**	**72**	**1,077**	983	137	1,120
Operations, maintenance, and administration	**329**	**(6)**	**323**	308	(5)	303
Asset impairment reversals	**(1)**	**1**	**-**	(18)	18	-
Restructuring provision	**-**	**-**	**-**	(2)	2	-
Taxes, other than income taxes	**20**	**-**	**20**	22	-	22
Intersegment cost allocation	**10**	**-**	**10**	11	-	11
Insurance recovery	**-**	**(1)**	**(1)**	-	-	-
Gain on sale of assets	**-**	**-**	**-**	-	(1)	(1)
EBITDA	**647**	**78**	**725**	662	123	785
Depreciation and amortization	**382**	**41**	**423**	365	43	408
Decrease in finance lease receivable	**-**	**2**	**2**	-	1	1
Operating income	**265**	**35**	**300**	297	79	376

(1) Refer to the Current Accounting Changes section of this MD&A for a description of prior period restatements.

(2) 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.

(3) Availability, production, and installed capacity include assets under generation operations and finance leases.

(4) Adjusted for economic dispatching at Centralia Thermal.

(5) We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated. Gross capacity reflects the basis of consolidation of underlying assets, while net capacity deducts capacity attributable to non-controlling interests in these assets.

Coal: *TransAlta owns and operates coal-fired facilities and related mining operations in Canada and the U.S. Coal revenues and overall profitability are derived from the availability and production of electricity. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2013 Annual MD&A.*

Canadian Coal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Availability (%)	**88.6**	74.9	**87.6**	78.2
Contract production (GWh)	**5,401**	4,158	**15,316**	12,269
Merchant production (GWh)	**999**	983	**3,208**	2,656
Total production (GWh)	**6,400**	5,141	**18,524**	14,925
Gross installed capacity (MW)	**3,771**	3,491	**3,771**	3,491
Net installed capacity (MW)	**3,576**	3,296	**3,576**	3,296
Revenues	**260**	249	**750**	664
Fuel and purchased power	**113**	101	**323**	267
Comparable gross margin[1]	**147**	148	**427**	397
Operations, maintenance, and administration	**52**	50	**147**	147
Taxes, other than income taxes	**3**	3	**9**	9
Gain on sale of assets	**-**	(1)	**-**	(1)
Intersegment cost allocation	**1**	1	**3**	3
Comparable EBITDA[1]	**91**	95	**268**	239
Depreciation and amortization	**72**	70	**216**	210
Comparable operating income[1]	**19**	25	**52**	29
Sustaining capital expenditures:				
Routine capital	**13**	25	**38**	44
Mining equipment and land purchases	**19**	18	**27**	38
Finance leases	**3**	3	**7**	7
Planned major maintenance	**17**	29	**81**	88
Total	**52**	75	**153**	177

Production for the three and nine months ended Sept. 30, 2014 increased 1,259 GWh and 3,599 GWh, respectively, compared to the same periods in 2013, primarily due to better availability as a result of the Keephills Unit 1 outage in 2013 and the return to service of Sundance Units 1 and 2. Increases in paid curtailments from our PPA counterparties following lower prices in Alberta have offset impacts on total production. For the balance of 2014, there are no further scheduled planned major maintenance outages on plants we operate.

For the three months ended Sept. 30, 2014, comparable gross margin decreased slightly compared to 2013. We benefited from increased contract production associated with reduced outages compared to the same period in 2013, allowing for increased revenue and contributing to decreasing unit fuel costs. Increases in contract revenue were limited by lower market-based production incentive rates under the terms of the PPAs, due to lower market prices. The effects of spot prices reductions on our merchant production were partially mitigated by our hedging program.

(1) 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.

For the nine months ended Sept. 30, 2014, comparable gross margin increased by $30 million compared to the same period in 2013, primarily as a result of lower unplanned outages, lower coal costs, and contract price escalations, partially offset by lower Alberta prices. In the first half of 2013, we had to settle financial contracts at high prices due to lower than expected generation during unplanned outages.

For the three and nine months ended Sept. 30, 2014, we have maintained comparable OM&A costs consistent with the same periods in 2013 despite much higher operating capacity with Sundance Units 1 and 2 returning to service. This was achieved through reduced maintenance costs associated with lower unplanned outages and the implementation of an initiative to reduce contract labour, staff overtime work, and material usage.

Depreciation and amortization for the three and nine months ended Sept. 30, 2014 increased compared to the same periods in 2013 due to an increased asset base, primarily related to Sundance Units 1 and 2 returning to service.

For the three and nine months ended Sept. 30, 2014, sustaining capital expenditures decreased $23 million and $24 million, respectively, compared to the same periods in 2013. The reduction is mainly attributable to mining activities, due to completion in 2013 of dragline and shovel major maintenance and to purchases of heavy equipment, in anticipation of production ramp-up to the current levels.

U.S. Coal

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2014	2013	**2014**	2013
Availability (%)	**96.9**	97.6	**80.3**	72.7
Adjusted availability (%)[1]	**96.9**	97.6	**86.9**	90.8
Production (GWh)	**2,254**	2,421	**4,740**	4,231
Gross and net installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**109**	110	**259**	233
Fuel and purchased power	**84**	77	**176**	142
Comparable gross margin	**25**	33	**83**	91
Operations, maintenance, and administration	**11**	11	**34**	31
Taxes, other than income taxes	**1**	1	**2**	3
Intersegment cost allocation	**1**	1	**4**	5
Comparable EBITDA	**12**	20	**43**	52
Depreciation and amortization	**13**	14	**40**	41
Comparable operating income (loss)	**(1)**	6	**3**	11
Sustaining capital expenditures:				
Routine capital	**2**	1	**3**	5
Planned major maintenance	**-**	1	**9**	8
Total	**2**	2	**12**	13

For the three months ended Sept. 30, 2014, production decreased 167 GWh compared to the same period in 2013 due to constraints in rail transport of coal and lower availability.

(1) Adjusted for economic dispatching.

Production for the nine months ended Sept. 30, 2014 increased 509 GWh compared to the same period in 2013 due to lower economic dispatching as a result of certain months during the period in which higher prices made production more economic. In periods of low market prices, such as during spring runoff, it can be more economic for us to not produce power at Centralia Thermal and purchase power in the market to satisfy our contractual obligations.

For the three and nine months ended Sept. 30, 2014, comparable EBITDA decreased by $8 million and $9 million, respectively, compared to the same periods in 2013, primarily due to compressed margin caused by curtailments from expected constraints in coal supply, lower volumes of higher priced hedges, higher cost of purchased power during periods of market curtailment, and escalation in fuel input costs, partially offset by increased power prices.

Gas: *TransAlta owns and operates natural gas-fired facilities in Canada, the U.S., and Australia. Gas revenues and overall profitability are derived from the availability and production of electricity and steam. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2013 Annual MD&A.*

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2014	2013	**2014**	2013
Availability (%)	**93.7**	93.1	**92.9**	93.7
Production (GWh)(1)	**1,720**	2,009	**5,567**	5,968
Gross installed capacity (MW)(1), (2)	**1,779**	1,779	**1,779**	1,779
Net installed capacity (MW)(1), (2)	**1,618**	1,618	**1,618**	1,618
Revenues	**162**	167	**575**	526
Fuel and purchased power	**60**	65	**266**	202
Comparable gross margin	**102**	102	**309**	324
Operations, maintenance, and administration	**24**	25	**77**	74
Taxes, other than income taxes	**-**	1	**2**	3
Intersegment cost allocation	**1**	1	**2**	1
Comparable EBITDA	**77**	75	**228**	246
Depreciation and amortization	**28**	26	**83**	80
Decrease in finance lease receivable	**1**	-	**2**	1
Comparable operating income	**48**	49	**143**	165
Sustaining capital expenditures:				
Routine capital	**5**	3	**13**	10
Planned major maintenance	**15**	4	**39**	21
Total	**20**	7	**52**	31

Production for the three and nine months ended Sept. 30, 2014 decreased 289 GWh and 401 GWh, respectively, compared to the same periods in 2013, primarily due to the reduced contribution from our Ottawa facility under the terms of the new contract effective Jan. 1, 2014 and the timing of a planned outage.

For the three months ended Sept. 30, 2014, comparable EBITDA was comparable to the same period in 2013, as the effects of lower Alberta prices on our Poplar Creek facility and reduced contribution from our Ottawa facility were offset by mark-to-market gains on certain Ontario gas purchase contracts and stored gas that are used as fuel or for trading purposes. These mark-to-market gains are offset by losses in the Energy Trading Segment.

(1) Includes production capacity for Fort Saskatchewan and Solomon power stations, which have been accounted for as finance leases.

(2) The Centralia gas plant is currently not in operation. We are currently assessing the generation needs of the region and the financial feasibility of bringing the plant back into operation.

Comparable EBITDA for the nine months ended Sept. 30, 2014 decreased by $18 million compared to the same period in 2013, primarily due to lower Alberta prices and the reduced contribution from our Ottawa facility under the terms of the contract. Those decreases in comparable EBITDA were partially offset by the benefits achieved through resale of higher priced excess gas during unplanned outages in 2014. The decreased contribution from the Ottawa contract was included in our 2014 full year EBITDA forecast. The new capacity-based contract is consistent with our contracting strategy and its twenty-year duration supports continued investment in the facility.

For the three and nine months ended Sept. 30, 2014, sustaining capital expenditures increased compared to the same periods in 2013, mainly due to an increase in planned major maintenance activities, including outages at Sarnia, Ottawa, and Poplar Creek.

Renewables: *TransAlta owns and operates hydro and wind facilities in Canada and the U.S. Renewable revenues and overall profitability are derived from the availability of water and wind resources and the production of electricity, as well as ancillary services such as system support. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2013 Annual MD&A.*

Wind

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Availability (%)	**94.6**	92.9	**94.1**	93.5
Production (GWh)	**532**	432	**2,193**	1,837
Gross installed capacity (MW)	**1,289**	1,145	**1,289**	1,145
Net installed capacity (MW)	**965**	926	**965**	926
Revenues	**43**	39	**172**	165
Fuel and purchased power	**3**	3	**10**	10
Comparable gross margin	**40**	36	**162**	155
Operations, maintenance, and administration	**12**	9	**35**	28
Taxes, other than income taxes	**2**	1	**5**	5
Intersegment cost allocation	**-**	1	**1**	1
Comparable EBITDA	**26**	25	**121**	121
Depreciation and amortization	**22**	20	**66**	58
Comparable operating income	**4**	5	**55**	63
Sustaining capital expenditures:				
Routine capital	**1**	-	**2**	2
Planned major maintenance	**1**	1	**5**	3
Total	**2**	1	**7**	5

Production for the three and nine months ended Sept. 30, 2014 increased 100 GWh and 356 GWh, respectively, compared to the same periods in 2013, primarily due to the contribution from recently added facilities and higher wind volumes in Eastern Canada. The increase in availability is associated with our operational improvement strategy focused on higher-priced, contracted facilities.

For the three and nine months ended Sept. 30, 2014, comparable EBITDA was consistent with the same periods in 2013, as increased production offset lower prices in Alberta.

Depreciation and amortization for the three and nine months ended Sept. 30, 2014 increased by $2 million and $8 million, respectively, compared to the same periods in 2013, primarily due to the higher asset based associated with recently added facilities.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Production (GWh)	**539**	707	**1,457**	1,717
Gross installed capacity (MW)	**913**	913	**913**	913
Net installed capacity (MW)	**882**	893	**882**	893
Revenues	**40**	58	**104**	159
Fuel and purchased power	**4**	3	**8**	6
Comparable gross margin	**36**	55	**96**	153
Operations, maintenance, and administration	**10**	4	**30**	23
Taxes, other than income taxes	**-**	1	**2**	2
Intersegment cost allocation	**-**	-	**-**	1
Insurance recovery	**-**	-	**(1)**	-
Comparable EBITDA	**26**	50	**65**	127
Depreciation and amortization	**6**	5	**18**	19
Comparable operating income	**20**	45	**47**	108
Sustaining capital expenditures:				
Routine capital	**2**	1	**13**	4
Planned major maintenance	**1**	1	**1**	1
Total	**3**	2	**14**	5

Production for the three and nine months ended Sept. 30, 2014 decreased 168 GWh and 260 GWh, respectively, compared to the same periods in 2013, due to lower water resource in Western Canada and lower economic incentive to run water. In 2013, water inflows in Western Canada were much higher than normal.

Comparable gross margin decreased by $19 million and $57 million, respectively, for the three and nine months ended Sept. 30, 2014 compared to the same periods in 2013, primarily as a result of lower market pricing in Alberta for power and ancillary services and lower production. Lower prices and low price volatility in Alberta limited our ability to take advantage of our flexibility to produce electricity during higher priced hours.

The $6 million and $7 million increase in OM&A expense during the three and nine months ended Sept. 30, 2014, respectively, compared to the same periods in 2013, is associated primarily with the return to regular maintenance activities after last year's disruptions from the flood.

For the nine months ended Sept. 30, 2014, the increase in sustaining capital expenditures compared to the same period in 2013 is mainly due to flood recovery expenditures.

Equity Investments

As outlined in the Significant Events section of this MD&A, we completed the sale of our interests in CE Gen and CalEnergy in June 2014. We continue to be the beneficial owner of a 50 per cent interest in Wailuku until the proposed sale closes in December 2014. The Wailuku hydro facility has 10 MW of gross generating capacity (5 MW net ownership interest).

The equity method was used to account for the results of the CE Gen, CalEnergy, and Wailuku joint ventures for the months of January and February 2014, but ceased effective March 1, 2014 with classification of these investments as assets held for sale in compliance with IFRS requirements.

The table below summarizes key operational information adjusted to reflect our interest in these investments:

	2 months ended Feb. 28, 2014	3 months ended Sept. 30, 2013	9 months ended Sept. 30, 2013
Availability (%)	**97.1**	91.5	90.1
Production (GWh):			
Gas	**127**	93	301
Renewables	**187**	285	863
Total production	**314**	378	1,164

Our investment in TAMA Transmission continues to be accounted for using the equity method.

Energy Trading: *Derives revenue and earnings from the wholesale marketing and trading of electricity and other energy-related commodities and derivatives. Achieving gross margins, while remaining within Value at Risk ("VaR") limits, is a key measure of Energy Trading's activities. Refer to the Value at Risk and Trading Positions discussion in the Risk Management section of our 2013 Annual MD&A for further discussion on VaR.*

Energy Trading markets our production through short-term and long-term contracts, ensures cost effective and reliable fuel supply, and seeks to capture margin upside within dynamic market conditions. We leverage our core marketing capabilities by also serving third party customers' energy supply and marketing needs.

Our marketing commitments are backed by our own supply and through the acquisition of third party supply and proprietary marketing assets, such as transmission, transportation, and storage rights. In the course of managing our portfolio, we actively seek to take advantage of our knowledge of physical power and fuel markets to capture incremental arbitrage margins.

All activities are managed within our core markets and within our low to moderate risk profile. Direct marketing of our own generation is reported in the Generation Segment results. All activities indirectly related to our assets and all other marketing activities are reported in the Energy Trading Segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2013 Annual MD&A.

The results of the Energy Trading Segment, with all trading results presented on a net basis, are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Revenues and comparable gross margin	**3**	22	**76**	53
Operations, maintenance, and administration	**9**	9	**36**	23
Intersegment cost allocation	**(3)**	(4)	**(10)**	(11)
Comparable EBITDA and comparable operating income (loss)	**(3)**	17	**50**	41

For the three months ended Sept. 30, 2014, comparable EBITDA decreased by $20 million compared to the same period in 2013, primarily due to lower commodity price volatility in Alberta and the western U.S. which impacted Energy Trading's ability to generate gross margin. In addition, timing differences related to supplying gas to our Eastern assets negatively impacted our gross margin in the third quarter, which is offset by gains in the Gas results.

Year-to-date comparable EBITDA increased by $9 million to $50 million as a result of extreme weather events which resulted in unprecedented gas and power commodity price volatility in eastern markets during the first quarter of 2014, which positively impacted our ability to optimize our portfolio of generation, transportation, transmission, and storage assets. We also capitalized on low risk arbitrage opportunities brought about by the extreme market volatility. The increase was partially offset by higher corporate cost allocations and higher performance-based compensation costs driven by the strong results.

We expect the Energy Trading gross margin to remain close to historical levels for the balance of the year.

Corporate: *Our Generation and Energy Trading segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, procurement, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.*

The expenses incurred by the Corporate Segment are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Operations, maintenance, and administration and taxes other than income taxes	**(17)**	(16)	**(40)**	(45)
Depreciation and amortization	**7**	6	**20**	17
Comparable operating loss	**(24)**	(22)	**(60)**	(62)
Sustaining capital expenditures:				
Routine capital	**5**	6	**17**	14
Total	**5**	6	**17**	14

For the three months ended Sept. 30, 2014, OM&A expenses were consistent compared to the same period in 2013.

For the nine months ended Sept. 30, 2014, OM&A expense decreased by $5 million compared to the same period in 2013, primarily due to a change in the way in which certain overhead cost allocations are made within the organization, partially offset by higher incentive-based compensation.

Routine capital expenditures for the nine months ended Sept. 30, 2014 increased compared to the same period in 2013, primarily as a result of an increase in corporate information technology expenditures.

NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Interest on debt	**60**	61	**179**	179
Capitalized interest	**(1)**	-	**(1)**	(2)
Interest expense	**59**	61	**178**	177
Accretion of provisions	**5**	4	**14**	13
Net interest expense	**64**	65	**192**	190

For the three and nine months ended Sept. 30, 2014, net interest expense was comparable to the same periods in 2013 due to lower long-term debt levels, offset by unfavourable foreign exchange impacts.

INCOME TAXES

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Earnings before income taxes	**31**	45	**90**	80
(Income) loss attributable to non-controlling interests	**(9)**	3	**(35)**	(16)
Equity (income) loss	**-**	(2)	**-**	5
Impacts associated with certain de-designated and ineffective hedges	**(35)**	11	**(7)**	60
Asset impairment	**(1)**	(18)	**(1)**	(18)
Restructuring provision	**-**	(1)	**-**	(3)
Gain on sale of assets	-	-	**(1)**	(10)
Sundance Units 1 and 2 return to service	**-**	15	**-**	15
Loss on assumption of pension obligations	**-**	-	**-**	29
Insurance recovery	**-**	-	**(1)**	-
California claim	**-**	-	**5**	-
Foreign exchange loss on California claim	**2**	-	**2**	-
Flood-related maintenance costs, net of insurance recovery	**4**	4	**6**	5
Earnings (loss) attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**(8)**	57	**58**	147
Income tax expense (recovery)	**18**	48	**33**	41
Income tax (expense) recovery related to impacts associated with certain de-designated and ineffective hedges	**(12)**	4	**(2)**	21
Income tax expense related to asset impairment	**-**	(5)	**-**	(5)
Income tax (expense) recovery related to restructuring provision	**-**	(1)	**-**	(1)
Income tax recovery (expense) related to gain on sale of assets	**-**	-	**1**	(1)
Income tax recovery related to sale of investment	**-**	-	**36**	-
Income tax recovery related to Sundance Units 1 and 2 return to service	**-**	4	**-**	4
Income tax recovery (expense) related to write off of deferred income tax assets	**(12)**	(40)	**(63)**	(40)
Income tax recovery related to loss on assumption of pension obligations	**-**	-	**-**	7
Income tax recovery related to California claim	**-**	-	**1**	-
Income tax recovery related to foreign exchange loss on California claim	**1**	-	**1**	-
Income tax recovery related to flood-related maintenance costs, net of insurance recovery	**1**	1	**1**	1
Income tax expense (recovery) excluding non-comparable items	**(4)**	11	**8**	34
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items (%)	**50**	19	**14**	23

The income tax expense excluding non-comparable items for the three and nine months ended Sept. 30, 2014 decreased compared to the same periods in 2013, due to lower comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three months ended Sept. 30, 2014 increased compared to the same period in 2013, 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 pre-tax income is earned.

For the nine months ended Sept. 30, 2014, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items decreased compared to the same period in 2013, due to the effect of certain deductions that do not fluctuate with earnings, changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, and the effect of certain prior year amounts that do not fluctuate with earnings.

During the three and nine months ended Sept. 30, 2014, $13 million and $27 million (2013 - $40 million and $40 million), respectively, of deferred income tax assets were written off related to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. We wrote these assets off as it was no longer considered probable that sufficient taxable income would be available from our directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2014 increased $13 million and $20 million, respectively, compared to the same periods in 2013, primarily due to earnings at TransAlta Renewables, which was formed as a separate public entity in August 2013, and better performance at TA Cogen associated with the deferral of a planned outage to 2015. As outlined in the Significant Events section of this MD&A, we completed a secondary offering of the common shares of TransAlta Renewables on April 29, 2014. As a result, the public share ownership of TransAlta Renewables increased from 19.4 per cent to 29.7 per cent.

ADDITIONAL IFRS MEASURES

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income (loss) in our Condensed Consolidated Statements of Earnings (Loss) for the three and nine months ended Sept. 30, 2014 and 2013. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

EARNINGS AND OTHER MEASURES ON A COMPARABLE BASIS

Presenting non-IFRS measures such as earnings on a comparable basis, comparable gross margin, comparable operating income, and comparable EBITDA from period to period provides management and investors with supplemental information to evaluate earnings trends in comparison with results from prior periods. In calculating these items, we exclude the impact related to certain hedges that are either de-designated or deemed ineffective for accounting purposes, as management believes that these transactions are not representative of our business operations and that these are still effective economic hedges. As these gains (losses) have already been recognized in earnings in current or prior periods, future reported earnings will be lower; however, the expected cash flows from these contracts will not change.

Other adjustments to earnings, such as those included in the earnings on a comparable basis calculation, have also been excluded 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.

Presenting comparable EBITDA from period to period provides management and investors with a proxy for the amount of cash generated from operating activities before net interest expense, non-controlling interests, income taxes, and working capital adjustments.

Comparable operating income and EBITDA also include the earnings from the finance lease facilities that we operate. The finance lease income is used as a proxy for the operating income and EBITDA of these facilities.

A reconciliation of comparable results to reported results for the three months ended Sept. 30, 2014 and 2013 is as follows:

	3 months ended Sept. 30, 2014				3 months ended Sept. 30, 2013[1]			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**639**	**13** [2]	**(35)** [4]	**617**	623	11 [2]	11 [4]	645
Fuel and purchased power	**277**	**(13)** [3]	**-**	**264**	265	(16) [3]	-	249
Gross margin	**362**	**26**	**(35)**	**353**	358	27	11	396
Operations, maintenance, and administration	**138**	**-**	**(4)** [5]	**134**	128	-	(4) [5]	124
Asset impairment charges (reversals)	**(1)**	**-**	**1** [6]	**-**	(18)	-	18 [6]	-
Restructuring provision	**-**	**-**	**-**	**-**	(1)	-	1 [6]	-
Taxes, other than income taxes	**7**	**-**	**-**	**7**	7	-	-	7
Insurance recovery	**-**	**-**	**-**	**-**	-	-	-	-
Gain on sale of assets	**-**	**-**	**-**	**-**	-	(1) [9]	-	(1)
EBITDA	**218**	**26**	**(32)**	**212**	242	28	(4)	266
Depreciation and amortization	**135**	**13** [3]	**-**	**148**	124	17 [3],[9]	-	141
Decrease in finance lease receivable	**-**	**1** [2]	**-**	**1**	-	-	-	-
Operating income	**83**	**12**	**(32)**	**63**	118	11	(4)	125
Finance lease income	**12**	**(12)** [2]	**-**	**-**	11	(11) [2]	-	-
Foreign exchange gain (loss)	**-**	**-**	**2** [6]	**2**	(6)	-	-	(6)
Sundance Units 1 and 2 return to service	**-**	**-**	**-**	**-**	(15)	-	15 [6]	-
Equity income	**-**	**-**	**-**	**-**	2	-	-	2
Earnings before interest and taxes	**95**	**-**	**(30)**	**65**	110	-	11	121
Net interest expense	**64**	**-**	**-**	**64**	65	-	-	65
Income tax expense (recovery)	**18**	**-**	**(22)** [7]	**(4)**	48	-	(37) [10]	11
Net earnings (loss)	**13**	**-**	**(8)**	**5**	(3)	-	48	45
Non-controlling interests	**10**	**-**	**(1)** [8]	**9**	(3)	-	-	(3)
Net earnings (loss) attributable to TransAlta shareholders	**3**	**-**	**(7)**	**(4)**	-	-	48	48
Preferred share dividends	**9**	**-**	**-**	**9**	9	-	-	9
Net earnings (loss) attributable to common shareholders	**(6)**	**-**	**(7)**	**(13)**	(9)	-	48	39
Weighted average number of common shares outstanding in the period	**273**			**273**	266			266
Net earnings (loss) per share attributable to common shareholders	**(0.03)**			**(0.05)**	(0.03)			0.15

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(1) Refer to the Current Accounting Changes section of this MD&A for a description of prior period restatements.

(2) Finance lease income and decrease in finance lease receivable used as a proxy for operating income.

(3) Mine depreciation that is included in fuel and purchased power.

(4) Impacts associated with certain de-designated and ineffective hedges.

(5) Flood-related maintenance costs, net of insurance recoveries.

(6) Non-comparable item.

(7) Writedown of deferred income tax assets and net tax effect of all comparable adjustments.

(8) Non-comparable item attributable to non-controlling interest.

(9) Gain on sale of property, plant and equipment that is included in depreciation.

(10) Net tax effect of all comparable adjustments.

A reconciliation of comparable results to reported results for the nine months ended Sept. 30, 2014 and 2013 is as follows:

	9 months ended Sept. 30, 2014				9 months ended Sept. 30, 2013[1]			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	1,905	38 [2]	(7) [5]	1,936	1,705	35 [2]	60 [5]	1,800
Fuel and purchased power	824	(41) [3]	-	783	669	(42) [3]	-	627
Gross margin	1,081	79	(7)	1,153	1,036	77	60	1,173
Operations, maintenance, and administration	404	-	(6) [6]	398	376	-	(5) [6]	371
Asset impairment charges (reversals)	(1)	-	1 [7]	-	(18)	-	18 [7]	-
Restructuring provision	-	-	-	-	(3)	-	3 [7]	-
Taxes, other than income taxes	21	-	-	21	22	-	-	22
Insurance recovery	-	(1) [4]	-	(1)	-	-	-	-
Gain on sale of assets	-	-	-	-	-	(1) [10]	-	(1)
EBITDA	657	80	(2)	735	659	78	44	781
Depreciation and amortization	402	41 [3]	-	443	382	43 [3],[10]	-	425
Decrease in finance lease receivable	-	2 [2]	-	2	-	1 [2]	-	1
Operating income	255	37	(2)	290	277	34	44	355
Finance lease income	36	(36) [2]	-	-	34	(34) [2]	-	-
Foreign exchange gain (loss)	(7)	-	2 [7]	(5)	(2)	-	-	(2)
Gain on sale of assets	1	-	(1) [8]	-	10	-	(10) [7]	-
California claim	(5)	-	5 [7]	-	-	-	-	-
Sundance Units 1 and 2 return to service	-	-	-	-	(15)	-	15 [7]	-
Insurance recovery	2	(1) [4]	(1) [7]	-	-	-	-	-
Equity loss	-	-	-	-	(5)	-	-	(5)
Loss on assumption of pension obligations	-	-	-	-	(29)		29 [7]	-
Earnings before interest and taxes	282	-	3	285	270	-	78	348
Net interest expense	192	-	-	192	190	-	-	190
Income tax expense (recovery)	33	-	(25) [9]	8	41	-	(7) [11]	34
Net earnings	57	-	28	85	39	-	85	124
Non-controlling interests	36	-	(1)	35	16	-	-	16
Net earnings attributable to TransAlta shareholders	21	-	29	50	23	-	85	108
Preferred share dividends	28	-	-	28	28	-	-	28
Net earnings (loss) attributable to common shareholders	(7)	-	29	22	(5)	-	85	80
Weighted average number of common shares outstanding in the period	272			272	262			262
Net earnings (loss) per share attributable to common shareholders	(0.03)			0.08	(0.02)			0.31

(1) Refer to the Current Accounting Changes section of this MD&A for a description of prior period restatements.

(2) Finance lease income and decrease in finance lease receivable used as a proxy for operating income.

(3) Mine depreciation that is included in fuel and purchased power.

(4) Comparable portion of insurance recovery.

(5) Impacts associated with certain de-designated and ineffective hedges.

(6) Flood-related maintenance costs, net of insurance recoveries.

(7) Non-comparable item.

(8) Gain on sale of CE Gen, Blackrock, and CalEnergy.

(9) Writedown of deferred income tax assets and net tax effect of all comparable adjustments.

(10) Gain on sale of property, plant and equipment that is included in depreciation.

(11) Net tax effects of all comparable adjustments.

FINANCIAL POSITION

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2013 to Sept. 30, 2014:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	203	Timing of receipts and payments, sale of investments, and financing activities
Accounts receivable	(128)	Timing of customer receipts and seasonality of revenues
Prepaid expenses	20	Prepayment of annual insurance premiums, royalties, and service agreements
Investments	(192)	Sale of CE Gen
Finance lease receivable (current and long-term)	13	Favourable changes in foreign exchange rates
Property, plant, and equipment, net	(31)	Depreciation for the period, partially offset by additions and favourable changes in foreign exchange rates
Deferred income tax assets	(71)	Writedown of deferred income tax asset and changes in temporary differences
Risk management assets (current and long-term)[1]	130	Gains on long-term power sale contract
Accounts payable and accrued liabilities	(37)	Timing of payments and accruals, partially offset by higher capital accruals
Dividends payable	(30)	Reduction of quarterly dividend
Long-term debt (including current portion)	(196)	Reduction of borrowings under credit facility and payout on maturity of medium term notes, partially offset by the issuance of senior notes
Decommissioning and other provisions (current and long-term)	19	Fluctuations in period end discount rates
Defined benefit obligation and other long-term liabilities	(15)	Payment related to California claim, partially offset by increase in defined benefit obligation
Deferred income tax liabilities	(31)	Net deferred income tax recovery
Risk management liabilities (current and long-term)[1]	(23)	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	161	Net earnings for the period, gains on cash flow hedges recognized in other comprehensive income, and preferred shared issued, partially offset by declared dividends
Non-controlling interests	90	Sale of additional non-controlling interest in TransAlta Renewables, partially offset by non-controlling interests' portion of net earnings net of distributions

FINANCIAL INSTRUMENTS

Refer to *Note 19* of the notes to the audited annual consolidated financial statements within our 2013 Annual Report and *Note 9* of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2014 for details on Financial Instruments. Refer to the Risk Management section of our 2013 Annual Report and *Note 10* of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2013.

(1) After giving effect to the $160 million reduction in risk management assets and liabilities as at Dec. 31, 2013, as described in the Current Accounting Changes section of this MD&A.

Energy Trading may enter into commodity transactions involving non-standard features for which market observable 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 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.

At Sept. 30, 2014, total Level III financial instruments had a net asset carrying value of $170 million (Dec. 31, 2013 - $66 million net asset). The increase during the period is attributable primarily to decreased 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.

During the third quarter of 2014, one of our subsidiaries with Australian functional currency became exposed to future payments of JPY5.3 billion for the acquisition of components of property, plant, and equipment over the period to June 2017. The subsidiary's exposure to foreign exchange fluctuations is hedged using foreign currency forward purchase contracts.

Following the divestiture of CE Gen, Blackrock, and CalEnergy, and the repatriation of proceeds into Canadian funds, we de-designated approximately U.S.$180 million of debt from hedging U.S. net investments. During the third quarter of 2014, we de-designated an additional U.S.$90 million of U.S.-denominated debt hedging other U.S. operations. Prospectively, these tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

During the second quarter, we also de-designated the cash flow hedge of the foreign exchange exposure on a U.S.$20 million debt. No significant reclassifications from AOCI arise as a result of this discontinuation of hedge accounting.

STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2014 compared to the same periods in 2013:

3 months ended Sept. 30	2014	2013	Primary factors explaining change
Cash and cash equivalents, beginning of period	**94**	67	
Provided by (used in):			
Operating activities	**216**	253	Decrease in cash earnings of $36 million
Investing activities	**(158)**	(150)	Decrease in proceeds on sale of PP&E of $8 million and an increase in investing working capital of $17 million, partially offset by a decrease in additions to PP&E of $16 million
Financing activities	**94**	(115)	A decrease in repayments of borrowings under credit facilities and in repayments of long-term debt of $301 million, and an increase in proceeds on issuance of preferred shares of $161 million, partially offset by a decrease in net proceeds on sale of additional non-controlling interest in a subsidiary of $207 million, an increase in common share cash dividends of $28 million, and an increase in distributions paid to subsidiaries' non-controlling interest of $11 million
Translation of foreign currency cash	**(1)**	-	
Cash and cash equivalents, end of period	**245**	55	

9 months ended Sept. 30	2014	2013	Primary factors explaining change
Cash and cash equivalents, beginning of period	**42**	27	
Provided by (used in):			
Operating activities	**546**	601	Decrease in cash earnings of $44 million and a decrease in the change in working capital of $11 million
Investing activities	**(137)**	(460)	Increase in proceeds on sale of investments of $218 million, a decrease in additions to PP&E of $118 million, and a decrease in investing non-cash working capital balances of $21 million, partially offset by a decrease in realized gains on financial instruments of $26 million and a decrease in proceeds on disposal of PP&E of $9 million
Financing activities	**(206)**	(113)	An increase in repayments of borrowings under credit facilities and in repayments (net of issuances) of long-term debt of $127 million, a decrease in proceeds on sale of non-controlling interest in subsidiary of $78 million, an increase in common share cash dividends of $46 million, and an increase in distributions paid to subsidiaries' non-controlling interests of $20 million, partially offset by an increase in proceeds on issuance of preferred shares of $161 million and an increase in realized gains on financial instruments of $17 million
Cash and cash equivalents, end of period	**245**	55	

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk arises from our ability to meet general funding needs, engage in trading and hedging activities, and manage the assets, liabilities, and capital structure of the Corporation. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner.

Our liquidity needs are met through a variety of sources, including cash generated from operations, availability under our long-term credit facilities, and long-term debt or equity issued under our Canadian and U.S. shelf registrations. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling interest partners, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.1 billion as at Sept. 30, 2014 compared to $4.3 billion as at Dec. 31, 2013. Long-term debt decreased from Dec. 31, 2013 primarily due to the use of proceeds from the sale of CE Gen, Blackrock, and CalEnergy, and the secondary offering of TransAlta Renewables common shares, to pay down our credit facility borrowings and repay, in May, the scheduled maturity of a debenture, partially offset by the senior note offering also undertaken in May. Foreign exchange movements have offset some of the reduction.

Credit Facilities

At Sept. 30, 2014, we had a total of $2.1 billion (Dec. 31, 2013 - $2.1 billion) of committed credit facilities, of which $1.4 billion (Dec. 31, 2013 - $0.9 billion) was not drawn and is available, subject to customary borrowing conditions. At Sept. 30, 2014, the $0.7 billion (Dec. 31, 2013 - $1.2 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (Dec. 31, 2013 - $0.8 billion) and letters of credit of $0.4 billion (Dec. 31, 2013 - $0.4 billion).

In addition to the $1.4 billion available under the credit facilities, we have $245 million of available cash.

Share Capital

On Oct. 29, 2014, we had 275.1 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G first preferred shares outstanding. At Sept. 30, 2014, we had 273.4 million (Sept. 30, 2013 - 266.3 million) common shares issued and outstanding. At Sept. 30, 2014, we had 38.6 million (Sept. 30, 2013 - 32.0 million) first preferred shares issued and outstanding.

During the three and nine months ended Sept. 30, 2014, 1.6 million and 5.2 million, respectively (Sept. 30, 2013 - 4.2 million and 11.6 million, respectively) common shares were issued under the Dividend Reinvestment and Optional Common Share Purchase Plan (the “Plan”) for $19 million and $65 million, respectively (Sept. 30, 2013 - $55 million and $161 million, respectively).

On Aug. 15, 2014, we completed a public offering of 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $165 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.325 per share as approved by the Board of Directors, payable quarterly, yielding 5.30 per cent per annum, for the initial period ending Sept. 30, 2019. The dividend rate will reset on Sept. 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.80 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series G preferred shareholders have the right at their option to convert their shares into Series H Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter. The holders of Series H preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill yield plus 3.80 per cent.

On Oct. 29, 2014, we declared a quarterly dividend of $0.18 per share on common shares payable on Jan. 1, 2015.

On Oct. 29, 2014, we declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.501 per share on the Series G preferred shares, all payable on Dec. 31, 2014.

We issue common shares for the reinvestment of dividends, for cash proceeds, or upon exercise of stock options and other share-based payment plans.

Letters of Credit and Cash Collateral

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, energy trading activities, hedging activities, construction projects and purchase obligations. At Sept. 30, 2014, we provided letters of credit totalling $363 million (Dec. 31, 2013 - $370 million) and cash collateral of $17 million (Dec. 31, 2013 - $20 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.

CLIMATE CHANGE AND THE ENVIRONMENT

In Alberta there are requirements for coal-fired generation units to implement additional air emission controls for oxides of nitrogen (“NOx”) and sulphur dioxide (“SO_2”) once they reach the end of their respective PPAs, in most cases at 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta’s Clean Air Strategic Alliance (“CASA”). However, the release of the federal Greenhouse Gas (“GHG”) regulations creates a potential misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with the provincial government in an effort to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta’s generation supply.

On June 2, 2014, the U.S. Environmental Protection Agency (“EPA”) released draft regulations for managing greenhouse gas emissions from the power sector. These draft regulations target GHG emissions from all existing fossil-fired generation in the U.S.: coal, natural gas, and other hydrocarbon fuels. The draft regulations are designed to achieve a 30 per cent reduction from 2005 emission levels by 2030, for that sector. The proposed framework would establish 2030 emission rate goals, measured in pounds of carbon dioxide per MWh, for each State’s electricity sector.

The draft regulations require interim goals to be achieved between 2020 and 2030 and a final goal to be achieved by 2030, and maintained beyond. The goals are State-specific depending on circumstances. States are to be given broad freedom to achieve the goals in a variety of ways, ranging from single- or multi-state cap and trade programs, heat rate improvements, and fuel switching initiatives, to more prescriptive approaches, such as, renewable energy and conservation programs. States will develop their individual approaches or State Implementation Plans, which will subsequently have to be reviewed and approved by the EPA. The draft regulations are expected to be finalized by the EPA by June 2015, with State Implementation Plans submitted by June 2016. We believe that there will be no additional greenhouse gas regulatory burden on Centralia as a result of the draft regulations.

2014 OUTLOOK

Business Environment

Power Prices

Over the balance of 2014, power prices in Alberta are expected to be lower than 2013 as a result of more baseload generation. However, prices can vary based on supply and weather conditions. In the Pacific Northwest, we expect prices to settle lower than in 2013. Market prices in December 2013 increased as a result of significant cold weather. In Ontario, prices for the balance of the year are expected to be lower than 2013 despite higher natural gas prices due to fewer nuclear unit outages and increased wind capacity compared to 2013. While we did account for lower pricing in our guidance, recent market conditions have been weaker than anticipated and we believe these weak conditions could be sustained through the end of the year.

During the third quarter of 2014, we evaluated the recoverable amount of our cash-generating units for asset and goodwill impairment testing purposes, and found no significant impairment charges or reversals. The valuations incorporated the most current future power price assumptions available at the time of the valuation for assets with merchant capacity. Following Sept. 30, 2014, decreases in future power prices have been noted in the main markets in which we operate. These decreases have not been reflected into the valuations. Our U.S. Coal assets, which have previously been impaired, are particularly sensitive to future power price fluctuations. We will continue to monitor changes in future power prices as it pertains to asset impairment over the fourth quarter.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. We are in discussions with the Alberta government in an effort to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta’s generation supply. This may provide additional flexibility to coal-fired generators in meeting such regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of our 2013 Annual MD&A.

On Jan. 21, 2013, the Ontario government released a discussion paper for public input on reducing GHG emissions in the province, with the stated intent of developing GHG regulations for all major industrial sectors by 2015. No specific targets or regulatory approaches have yet been proposed.

The recently proposed EPA greenhouse gas regulations for existing power plants are not expected to significantly affect our U.S. operations. Regarding our Centralia coal-fired plant, TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State’s climate change program. We believe that there will be no additional greenhouse gas regulatory burden on Centralia given these commitments.

Effective January 2013, direct deliveries of power to the California Independent System Operator were subject to Cap and Trade Regulations established by the California Air Resource Board. We continue to monitor our GHG inventory into California.

In Australia, the Government repealed the nation’s carbon tax on July 17, 2014. This will eliminate the previous emission charges on our Australian gas-fired generation, although the impact is expected to be minimal as these emission charges were generally passed through to contracted customers. The Liberal Government has not yet implemented an alternative climate change program.

We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

Economic Environment

In 2014, we expect slow to moderate growth in all markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no material counterparty losses in the third quarter of 2014. We continue to monitor counterparty credit risk and have established risk management policies to mitigate counterparty risk. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase primarily due to the commencement of operations at our Solomon power station in Australia. Prior to the effect of any economic dispatching, overall production is expected to increase in 2014 compared to 2013 due to Sundance Units 1 and 2 returning to service, lower planned and unplanned outages, and the acquisition of Wyoming Wind. Overall availability is expected to be in the range of 88 to 90 per cent in 2014.

Contracted Cash Flows

As a result of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. 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 third quarter of 2014, approximately 90 per cent of our 2014 capacity was contracted. The average prices of our short-term physical and financial contracts for 2014 are approximately $55 per MWh in Alberta and approximately U.S.$40 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2014, on a standard cost per tonne basis, are expected to be seven to nine per cent lower than 2013 due to Sundance Units 1 and 2 operating for a full year and the benefits realized from insourcing operational accountability from Prairie Mines and Royalty Ltd. at the Highvale Mine during 2013.

Although we own the Centralia mine in the State of Washington, it is not currently operational. Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2014 is expected to increase by approximately one to three per cent.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges are recognized in net earnings.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America could reduce the year-to-year volatility of prices in the near term.

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 Trading

Earnings from our Energy Trading Segment are affected by prices and volatility in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure in order to maximize earnings while still maintaining an acceptable risk profile. Our 2014 objective for Energy Trading was to contribute between $50 million to $65 million in gross margin. Following strong performance in the first quarter we now expect Energy Trading to contribute between $80 million and $90 million in gross margin for the year as markets return to more normal volatility for the remainder of the year.

Exposure to Fluctuations in Foreign Currencies

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

Net Interest Expense

Net interest expense for 2014 is expected to be lower than in 2013 due to reduced debt levels resulting from the use of proceeds from the offering of preferred shares during the current quarter, the sale of CE Gen, Blackrock and CalEnergy, and the secondary offering of TransAlta Renewables' common shares to pay down our credit facility borrowings. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar can affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, we may need additional liquidity in the future. We expect to maintain adequate available liquidity under our committed credit facilities.

Accounting Estimates

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of our 2013 Annual MD&A, are based on the current economic environment and outlook. Under the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings, and the unrealized gains or losses associated with our risk management assets and liabilities, and asset valuation for our asset impairment calculations.

Income Taxes

The effective tax rate on earnings, excluding non-comparable items for 2014, is expected to be approximately 17 to 22 per cent, which is lower than the statutory tax rate of 25 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		2014		Target	
	Estimated spend	Spent to date[1]	Estimated spend	Spent to date[1]	completion date	Details
Project						
South Hedland Power Station[2]	572	13	73	13	Q2 2017	150 MW combined cycle power plant
Australia natural gas pipeline[3]	92	57	92	57	Q1 2015	270 kilometer pipeline to supply natural gas to our Solomon power station in Western Australia
Transmission	12	-	1	-	Q2 2015	Regulated transmission that receives a return on investment
Hydro life extension	15 - 20	9	15 - 20	9	Q4 2014	Generator replacement and turbine runner improvements to extend the life of selected plants
Total	**691 - 696**	**79**	**181 - 186**	**79**		

During the quarter, the scope of the transmission project was increased and the project was deferred until 2015. The incremental scope will also give rise to incremental rate base.

(1) Represents amounts spent as of Sept. 30, 2014.

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

(3) Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable. The total estimated project spend may change due to fluctuations in foreign exchange rates.

Sustaining and Productivity Expenditures

For 2014, our estimate for total sustaining and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Spent to date[(1)]
Routine capital	Expenditures to maintain our existing generating capacity	135 - 140	86
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	45 - 50	27
Finance leases	Payments related to mining equipment under finance leases	5 - 10	7
Planned major maintenance	Regularly scheduled major maintenance	150 - 165	135
Total sustaining expenditures		**335 - 365**	**255**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	10 - 15	10
Total sustaining and productivity expenditures		**345 - 380**	**265**

Our planned major maintenance program relates to regularly scheduled major maintenance activities and includes costs related to inspection, repair and maintenance, and replacement of existing components. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

Details of the 2014 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2014	Spent to date[(1)]
Capitalized	95 - 105	55 - 60	150 - 165	135
Expensed	-	0 - 5	0 - 5	-
	95 - 105	55 - 65	150 - 170	135

	Coal	Gas and Renewables	Total	Lost to date[(1)]
GWh lost	2,030 - 2,040	380 - 390	2,410 - 2,430	2,268

Our estimate of the overall GWh of lost production due to our planned major maintenance program has decreased compared to what was reported in our 2013 annual MD&A as a result of the deferral of one outage from 2014 to 2015.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, dividends reinvested under the Plan, and capital markets. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment due to the highly contracted nature of our cash flows, our financial position, and the amount of capital available to us under existing committed credit facilities.

(1) Represents amounts spent as of Sept. 30, 2014.

CURRENT ACCOUNTING CHANGES

Inception Gains and Losses

We restated the Condensed Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Condensed Consolidated Statement of Financial Position were immaterial. Refer to *Note 9(C)* in our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2014 for further information on inception gains and losses.

Inventory Writedown

During the third quarter of 2014, we restated the Condensed Consolidated Statements of Earnings (Loss) for the periods ended Sept. 30, 2013 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as standalone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the three and nine months ended Sept. 30, 2013, increased by $5 million and $21 million, respectively. The inventory writedown for the three and nine months ended Sept. 30, 2014 amounts to $6 million.

IAS 32 *Financial Instruments: Presentation*

On Jan. 1, 2014, we adopted the amendments to IAS 32 *Financial Instruments: Presentation* regarding offsetting financial assets and financial liabilities. There was no impact of adopting the IAS 32 amendments on the unaudited interim condensed consolidated financial statements.

IAS 36 *Impairment of Assets*

On Jan. 1, 2014, the Corporation adopted the amended disclosure requirements of IAS 36 *Impairment of Assets.* The amended disclosure requirements did not have an impact on the unaudited interim condensed consolidated financial statements.

Comparative Figures

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

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:

I. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 Financial Instruments. IFRS 9 includes guidance, some of which was previously issued by the IASB, on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model. Please refer to Note 3 of our most recent annual consolidated financial statements for information regarding previously issued sections of IFRS 9.

The new requirements for impairment of financial assets introduce an expected-loss impairment model which requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

SELECTED QUARTERLY INFORMATION

	Q4 2013	Q1 2014	Q2 2014	**Q3 2014**
Revenue	587	775	491	**639**
Net earnings (loss) attributable to common shareholders	(66)	49	(50)	**(6)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.25)	0.18	(0.18)	**(0.03)**
Comparable net earnings (loss) per share	0.00	0.17	(0.04)	**(0.05)**

	Q4 2012	Q1 2013	Q2 2013	Q3 2013
Revenue	646	540	542	623
Net earnings (loss) attributable to common shareholders	39	(11)	15	(9)
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.15	(0.04)	0.06	(0.03)
Comparable net earnings per share	0.22	0.12	0.03	0.15

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

DISCLOSURE CONTROLS AND PROCEDURES

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the *Securities Exchange Act of 1934,* as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is 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 Sept. 30, 2014, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

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. 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", "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 and the completion and commissioning of projects under development, including major projects such as the South Hedland Power Project, and their attendant costs; expectations regarding the AESO's plans for resolving regional constraints on Alberta's transmission system; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the impact of certain hedges on future reported earnings and cash flows; expectations related to future earnings and cash flow from operating and contracting activities; 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, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding proceedings before the AUC as well as those relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewals of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; the estimated contribution of Energy Trading activities to gross margin; and expectations relating to the performance of TransAlta Renewables' assets.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and the availability of fuel supplies required to generate electricity; 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; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural or man-made disasters; the threat of domestic terrorism and cyber-attacks; equipment failure and our ability to carry out the repairs in a cost-effective manner or timely manner; energy trading risks; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions including delays in the permitting and construction of the South Hedland Power Project and the construction of the Australia Natural Gas Pipeline; the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives; and the satisfactory closing of the disposition of our interest in Wailuku.

The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2013 Annual MD&A and under the heading "Risk Factors" in our 2014 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties, and assumptions, the forward-looking events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(in millions of Canadian dollars except per share amounts)

Unaudited	3 months ended Sept. 30 **2014**	3 months ended Sept. 30 2013 *(Restated)**	9 months ended Sept. 30 **2014**	9 months ended Sept. 30 2013 *(Restated)**
Revenues	**639**	623	**1,905**	1,705
Fuel and purchased power *(Note 2)*	**277**	265	**824**	669
Gross margin	**362**	358	**1,081**	1,036
Operations, maintenance, and administration *(Note 6)*	**138**	128	**404**	376
Depreciation and amortization	**135**	124	**402**	382
Asset impairment reversals	**(1)**	(18)	**(1)**	(18)
Restructuring provision	**-**	(1)	**-**	(3)
Taxes, other than income taxes	**7**	7	**21**	22
Operating income	**83**	118	**255**	277
Finance lease income	**12**	11	**36**	34
Equity income (loss) *(Note 3)*	**-**	2	**-**	(5)
Net interest expense *(Note 4)*	**(64)**	(65)	**(192)**	(190)
Foreign exchange loss	**-**	(6)	**(7)**	(2)
Gain on sale of assets *(Note 3)*	**-**	-	**1**	10
Loss on assumption of pension obligations	**-**	-	**-**	(29)
California claim *(Note 5)*	**-**	-	**(5)**	-
Insurance recovery *(Note 6)*	**-**	-	**2**	-
Sundance Units 1 and 2 return to service	**-**	(15)	**-**	(15)
Earnings before income taxes	**31**	45	**90**	80
Income tax expense *(Note 7)*	**18**	48	**33**	41
Net earnings (loss)	**13**	(3)	**57**	39
Net earnings (loss) attributable to:				
TransAlta shareholders	**3**	-	**21**	23
Non-controlling interests *(Note 8)*	**10**	(3)	**36**	16
	13	(3)	**57**	39
Net earnings attributable to TransAlta shareholders	**3**	-	**21**	23
Preferred share dividends *(Note 14)*	**9**	9	**28**	28
Net earnings (loss) attributable to common shareholders	**(6)**	(9)	**(7)**	(5)
Weighted average number of common shares outstanding in the period *(millions)*	**273**	266	**272**	262
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 13)*	**(0.03)**	(0.03)	**(0.03)**	(0.02)

** 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)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2014**	2013	**2014**	2013
Net earnings (loss)	**13**	(3)	**57**	39
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**3**	17	**(8)**	28
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(2)	**-**	-	**-**	1
Total items that will not be reclassified subsequently to net earnings	**3**	17	**(8)**	29
Gains (losses) on translating net assets of foreign operations	**25**	(16)	**45**	16
Reclassification of translation gains on net assets of divested foreign operations *(Note 3)*	**-**	-	**(6)**	-
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(3)	**(19)**	15	**(37)**	(14)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax(4) *(Note 3)*	**-**	-	**7**	-
Gains (losses) on derivatives designated as cash flow hedges, net of tax(5)	**111**	(47)	**100**	(20)
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax(6)	**(49)**	35	**(27)**	(4)
Total items that will be reclassified subsequently to net earnings	**68**	(13)	**82**	(22)
Other comprehensive income	**71**	4	**74**	7
Total comprehensive income	**84**	1	**131**	46
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**73**	5	**88**	23
Non-controlling interests	**11**	(4)	**43**	23
	84	1	**131**	46

(1) Net of income tax expense of 1 and recovery of 3 for the three and nine months ended Sept. 30, 2014 (2013 - 6 and 10 expense), respectively.

(2) Net of income tax recovery of 1 for the nine months ended Sept. 30, 2013.

(3) Net of income tax recovery of 2 and 5 for the three and nine months ended Sept. 30, 2014 (2013 - 2 expense and 2 recovery), respectively.

(4) Net of income tax recovery of 1 for the nine months ended Sept. 30, 2014 (2013 - nil).

(5) Net of income tax expense of 44 and 37 for the three and nine months ended Sept. 30, 2014 (2013 - 22 and 26 recovery), respectively.

(6) Net of income tax expense of 7 and 1 for the three and nine months ended Sept. 30, 2014 (2013 - 8 and 3 recovery), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2014**	Dec. 31, 2013 *(Restated)**
Cash and cash equivalents	**245**	42
Accounts receivable *(Note 9)*	**345**	473
Current portion of finance lease receivable	**4**	3
Collateral paid *(Note 10)*	**17**	20
Prepaid expenses	**32**	12
Risk management assets *(Notes 9 and 10)*	**129**	113
Inventory *(Note 2)*	**86**	77
Income taxes receivable	**3**	8
Assets held for sale *(Note 3)*	**5**	-
	866	748
Investments *(Note 3)*	-	192
Long-term portion of finance lease receivable	**389**	377
Property, plant, and equipment *(Note 11)*		
Cost	**12,351**	12,024
Accumulated depreciation	**(5,189)**	(4,831)
	7,162	7,193
Goodwill	**461**	460
Intangible assets	**322**	323
Deferred income tax assets	**47**	118
Risk management assets *(Notes 9 and 10)*	**230**	116
Other assets	**91**	97
Total assets	**9,568**	9,624
Accounts payable and accrued liabilities	**410**	447
Current portion of decommissioning and other provisions	**21**	16
Risk management liabilities *(Notes 9 and 10)*	**69**	85
Income taxes payable	**-**	3
Dividends payable *(Note 13)*	**55**	85
Current portion of finance lease obligation	**10**	8
Current portion of long-term debt *(Notes 9 and 12)*	**716**	209
	1,281	853
Long-term debt *(Notes 9 and 12)*	**3,410**	4,113
Long-term portion of finance lease obligation	**24**	17
Decommissioning and other provisions	**330**	316
Deferred income tax liabilities	**428**	459
Risk management liabilities *(Notes 9 and 10)*	**96**	103
Defined benefit obligation and other long-term liabilities	**325**	340
Equity		
Common shares *(Note 13)*	**2,979**	2,913
Preferred shares *(Note 14)*	**943**	781
Contributed surplus	**9**	9
Deficit	**(869)**	(735)
Accumulated other comprehensive income (loss)	**5**	(62)
Equity attributable to shareholders	**3,067**	2,906
Non-controlling interests *(Note 8)*	**607**	517
Total equity	**3,674**	3,423
Total liabilities and equity	**9,568**	9,624

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

Commitments *(Note 15)*

Contingencies *(Note 16)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

9 months ended Sept. 30, 2014

Unaudited	**Common shares**	**Preferred shares**	**Contributed surplus**	**Deficit**	**Accumulated other comprehensive loss**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec. 31, 2013	2,913	781	9	(735)	(62)	2,906	517	3,423
Net earnings	-	-	-	21	-	21	36	57
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	9	9	-	9
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	66	66	7	73
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(8)	(8)	-	(8)
Total comprehensive income				21	67	88	43	131
Common share dividends	-	-	-	(147)	-	(147)	-	(147)
Preferred share dividends	-	-	-	(28)	-	(28)	-	(28)
Secondary offering of TransAlta Renewables Inc. shares *(Note 8)*	-	-	-	20	-	20	109	129
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(62)	(62)
Common shares issued	66	-	-	-	-	66	-	66
Preferred shares issued	-	162	-	-	-	162	-	162
Balance, Sept. 30, 2014	**2,979**	**943**	**9**	**(869)**	**5**	**3,067**	**607**	**3,674**

See accompanying notes.

9 months ended Sept. 30, 2013

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive loss	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2012	2,726	781	9	(362)	(136)	3,018	330	3,348
Net earnings	-	-	-	23	-	23	16	39
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	-	-	-	-	2	2	-	2
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(30)	(30)	7	(23)
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	28	28	-	28
Total comprehensive income (loss)				23	-	23	23	46
Common share dividends	-	-	-	(228)	-	(228)	-	(228)
Preferred share dividends	-	-	-	(28)	-	(28)	-	(28)
Formation of TransAlta Renewables Inc.	-	-	-	4	-	4	206	210
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(45)	(45)
Common shares issued	161	-	-	-	-	161	-	161
Balance, Sept. 30, 2013	2,887	781	9	(591)	(136)	2,950	514	3,464

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2014**	2013	**2014**	2013
Operating activities				
Net earnings (loss)	**13**	(3)	**57**	39
Depreciation and amortization	**148**	141	**443**	425
Gain on sale of assets *(Note 3)*	**-**	-	**(1)**	-
California claim *(Note 5)*	**-**	-	**(28)**	-
Accretion of provisions	**5**	4	**14**	13
Decommissioning and restoration costs settled	**(4)**	(6)	**(11)**	(19)
Deferred income tax expense (recovery) *(Note 7)*	**11**	38	**9**	5
Unrealized (gain) loss from risk management activities	**(29)**	(15)	**9**	44
Unrealized foreign exchange (gain) loss	**(4)**	4	**4**	5
Provisions	**(4)**	10	**-**	10
Asset impairment reversals	**(1)**	(18)	**(1)**	(18)
Sundance Units 1 and 2 return to service	**-**	15	**-**	15
Equity (income) loss *(Note 3)*	**-**	(2)	**-**	5
Other non-cash items	**5**	8	**1**	16
Cash flow from operations before changes in working capital	**140**	176	**496**	540
Change in non-cash operating working capital balances	**76**	77	**50**	61
Cash flow from operating activities	**216**	253	**546**	601
Investing activities				
Additions to property, plant, and equipment *(Note 11)*	**(144)**	(160)	**(324)**	(442)
Additions to intangibles	**(6)**	(8)	**(19)**	(21)
Addition to equity investments *(Note 3)*	**-**	-	**(13)**	(10)
Proceeds on sale of property, plant, and equipment	**2**	10	**2**	11
Proceeds on sale of equity investments *(Note 3)*	**-**	**-**	**218**	-
Realized gains (losses) on financial instruments	**3**	4	**(10)**	16
Net increase (decrease) in collateral received from counterparties	**(1)**	1	**(1)**	(1)
Net decrease in collateral paid to counterparties	**-**	-	**4**	2
Decrease in finance lease receivable	**1**	-	**2**	1
Other	**-**	(1)	**-**	1
Change in non-cash investing working capital balances	**(13)**	4	**4**	(17)
Cash flow used in investing activities	**(158)**	(150)	**(137)**	(460)
Financing activities				
Net increase (decrease) in borrowings under credit facilities *(Note 12)*	**1**	(299)	**(532)**	(170)
Repayment of long-term debt *(Note 12)*	**(2)**	(3)	**(207)**	(8)
Net proceeds on sale of additional non-controlling interest in subsidiary *(Note 8)*	**-**	-	**129**	-
Issuance of long-term debt *(Note 12)*	**-**	-	**434**	-
Dividends paid on common shares *(Note 13)*	**(29)**	(1)	**(110)**	(64)
Dividends paid on preferred shares *(Note 14)*	**(9)**	(9)	**(28)**	(28)
Net proceeds on issuance of preferred shares *(Note 14)*	**161**	-	**161**	-
Net proceeds on sale of non-controlling interest in subsidiary	**-**	207	**-**	207
Realized gains (losses) on financial instruments	**(6)**	-	**17**	-
Distributions paid to subsidiaries' non-controlling interests *(Note 8)*	**(19)**	(8)	**(63)**	(43)
Decrease in finance lease obligation	**(2)**	(3)	**(7)**	(7)
Other	**(1)**	1	**-**	-
Cash flow from (used in) financing activities	**94**	(115)	**(206)**	(113)
Cash flow from (used in) operating, investing, and financing activities	**152**	(12)	**203**	28
Effect of translation on foreign currency cash	**(1)**	-	**-**	-
Increase (decrease) in cash and cash equivalents	**151**	(12)	**203**	28
Cash and cash equivalents, beginning of period	**94**	67	**42**	27
Cash and cash equivalents, end of period	**245**	55	**245**	55
Cash income taxes paid (received)	**(6)**	8	**21**	33
Cash interest paid	**36**	39	**157**	158

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, these should be read in conjunction with the Corporation's most recent annual consolidated financial statements which are available on SEDAR at www.sedar.com.

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 assets and liabilities, 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 Board of Directors on Oct. 29, 2014.

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 and liabilities and disclosures of contingent assets and liabilities at the date of the unaudited interim condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation, and regulations.

Management has assessed that it is highly probable the sale described in Note 3 will close within a one-year time frame, thereby meeting the conditions of IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations* for presenting the assets as held for sale within current assets. Net earnings include the equity loss from these investments up to the date of this reclassification.

Refer to Note 2(W) of the 2013 audited annual consolidated financial statements for a more detailed discussion of the significant accounting judgments and key sources of estimation uncertainty.

2. ACCOUNTING CHANGES

A. Current Accounting Policy Changes

I. Inception Gains and Losses

In the first quarter of 2014, the Corporation restated the Condensed Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Condensed Consolidated Statement of Financial Position were immaterial. Refer to Note 9(C) for further information on inception gains and losses.

II. Inventory writedown

During the third quarter of 2014, the Corporation restated the Condensed Consolidated Statements of Earnings (Loss) for periods ended Sept. 30, 2013 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as standalone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the three and nine months ended Sept. 30, 2013, increased by $5 million and $21 million, respectively. The inventory writedown for the three and nine months ended Sept. 30, 2014 amounts to $6 million.

III. IAS 32 *Financial Instruments: Presentation*

On Jan. 1, 2014, the Corporation adopted the amendments to IAS 32 *Financial Instruments: Presentation*. There was no impact of adopting the IAS 32 amendments on the unaudited interim condensed consolidated financial statements.

IV. IAS 36 *Impairment of Assets*

On Jan. 1, 2014, the Corporation adopted the amended disclosure requirements of IAS 36 *Impairment of Assets.* The amended disclosure requirements did not have an impact on the unaudited interim condensed consolidated financial statements.

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:

I. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 Financial Instruments. IFRS 9 includes guidance, some of which was previously issued by the IASB, on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model.

Please refer to Note 3 of the Corporation's most recent annual consolidated financial statements for information regarding previously issued sections of IFRS 9.

The new requirements for impairment of financial assets introduce an expected-loss impairment model which requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. The Corporation is assessing the impact of adopting this standard 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.

3. DISPOSITION OF ASSETS

On June 12, 2014, the Corporation closed the previously announced sale of its 50 per cent interest in CE Generation, LLC ("CE Gen"), CalEnergy LLC, and the Blackrock development project to MidAmerican Renewables for gross proceeds of U.S.$200.5 million. The original consideration of U.S.$188.5 million was increased as a result of a U.S.$12 million contribution made by the Corporation in May, 2014. As a result of the sale, the Corporation recognized a pre-tax gain of $1 million ($2 million after-tax) as part of gains on sale of assets in the second quarter earnings. The gain includes reclassified cumulative translation gains on the divested net assets of $6 million, offset by related cumulative after-tax losses of $7 million from the related net investment hedge. The gain is reported in the Generation Segment.

The sale of Wailuku Holding Company, LLC ("Wailuku") is expected to close in the fourth quarter of 2014 for proceeds of U.S.$5 million, accordingly, the investment in Wailuku continues to be classified as held for sale.

4. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2014	2013	**2014**	2013
Interest on debt	**60**	61	**179**	179
Capitalized interest	**(1)**	-	**(1)**	(2)
Interest expense	**59**	61	**178**	177
Accretion of provisions	**5**	4	**14**	13
Net interest expense	**64**	65	**192**	190

5. CALIFORNIA CLAIM

On May 30, 2014, the Corporation announced that its settlement with California utilities, the California Attorney General and certain other parties (the "California Parties") to resolve claims related to the 2000 - 2001 power crisis in the State of California had been approved by the Federal Energy Regulatory Commission. The settlement provides for the payment by the Corporation of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to the Corporation from accounts receivable. The first payment of U.S.$26 million was paid in June, 2014 and the second is due in 2015. During the fourth quarter of 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to earnings of approximately U.S.$52 million. The finalization of the settlement in May, 2014, resulted in an additional pre-tax charge to second quarter earnings of U.S.$5 million.

6. INSURANCE RECOVERY

During the nine months ended Sept. 30, 2014, the Corporation received $8 million in insurance proceeds, of which $6 million was related to claims for repair costs on certain hydro facilities as a result of flooding during 2013 and accounted for as a reduction to period operations, maintenance, and administration. The balance, in the amount of $2 million, related to purchases of replacement equipment and business interruption insurance for various prior years claims.

7. INCOME TAXES

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Current income tax expense	**7**	10	**24**	35
Adjustments in respect of current income tax of previous years	**-**	-	**-**	1
Adjustments in respect of deferred income tax of a prior period	**-**	-	**2**	-
Deferred income tax recovery related to the origination and reversal of temporary differences	**(2)**	(2)	**(19)**	(28)
Deferred income tax recovery resulting from changes in tax rates or laws[(1)]	**-**	-	**-**	(7)
Deferred tax recovery arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period	**-**	-	**(37)**	-
Deferred income tax expense arising from the writedown of deferred income tax assets	**13**	40	**63**	40
Income tax expense	**18**	48	**33**	41

(1) Relates to the impact of adjusting the deferred tax rate to incorporate the Ontario M&P tax credit. Previously, the Corporation had been using the Ontario general corporate tax rate of 11.5 per cent.

Presented in the Condensed Consolidated Statements of Earnings (Loss) as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Current income tax expense	**7**	10	**24**	36
Deferred income tax expense	**11**	38	**9**	5
Income tax expense	**18**	48	**33**	41

During the three and nine months ended Sept. 30, 2014, $13 million and $27 million (2013 - $40 million and $40 million), respectively, of deferred income tax assets were written off related to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation wrote these assets off as it was no longer considered probable that sufficient 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.

8. NON-CONTROLLING INTERESTS

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

I. TransAlta Cogeneration L.P.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	2013	**2014**	2013
Revenues	**71**	55	**228**	212
Net earnings (loss)	**16**	(7)	**54**	28
Total comprehensive income (loss)	**17**	(5)	**68**	42
Amounts attributable to the non-controlling interest:				
Net earnings (loss)	**9**	(3)	**28**	14
Total comprehensive income (loss)	**10**	(4)	**35**	21
Distributions paid to the non-controlling interest	**12**	6	**43**	39

As at	**Sept. 30, 2014**	Dec. 31, 2013
Current assets	**52**	56
Long-term assets	**601**	632
Current liabilities	**(53)**	(56)
Long-term liabilities	**(55)**	(68)
Total equity	**(545)**	(564)
Equity attributable to the non-controlling interest	**(270)**	(280)
Non-controlling interest share (per cent)	**49.99**	49.99

II. TransAlta Renewables

On April 29, 2014, the Corporation completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. The offering resulted in gross proceeds to the Corporation of approximately $136 million. Following completion of the offering, TransAlta owns approximately 70.3 per cent of the common shares of TransAlta Renewables. As a result of the transaction, the carrying amount of the non-controlling interests was increased by $109 million to reflect the approximate 10.4 per cent increase in their relative interest in TransAlta Renewables and a $20 million gain, net of tax and issuance costs attributable to common shareholders, was recognized directly in retained earnings.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2014	**2013**	**2014**	**2013**
Revenues	**43**	44	**161**	175
Net earnings	**1**	2	**29**	36
Total comprehensive income	**1**	2	**29**	37
Amounts attributable to the non-controlling interests:				
Net earnings and total comprehensive income	**1**	-	**8**	2
Distributions paid to non-controlling interests	**7**	6	**20**	8

As at	**Sept. 30, 2014**	Dec. 31, 2013
Current assets	**35**	59
Long-term assets	**1,915**	1,954
Current liabilities	**(220)**	(100)
Long-term liabilities	**(689)**	(846)
Total equity	**(1,041)**	(1,067)
Equity attributable to non-controlling interests	**(337)**	(237)
Non-controlling interests share (per cent)	**29.7**	19.3

9. 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. Levels 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. 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 energy trading financial instruments include, in Level II, 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 asset or liability 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 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 energy trading 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.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at Sept. 30, 2014 is estimated to be a +/- $116 million (Dec. 31, 2013 - $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/-$88 million (Dec. 31, 2013 - $87 million) in the stress value stems from a long dated power sale contract that is designated as a cash flow hedge, while the remaining +/-$28 million (Dec. 31, 2013 - $18 million) accounts for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Information about the effects on fair values of significant unobservable inputs used in determining Level III fair values is as follows:

Description	**Effects on fair values as at Sept. 30, 2014**	**Valuation Technique**	**Unobservable input**	**Range**
Unit contingent power purchases	38	Historical analysis	Price discount	0.3 - 1.7 per cent
			Volumetric discount[1]	0 - 23 per cent
Long-term power sale	338	Long-term price forecast	Illiquid future power prices (per MW)	U.S.$23 - U.S.$63 and $78 - $113
Coal supply revenue sharing	(6)	Vanilla and exotic option valuation techniques	Volumes (MWh)	16 - 24 per cent of available generation
			Illiquid commodity forward price volatilities	6 - 27 per cent
			Illiquid future power prices (per MWh)	U.S.$23 - U.S.$63
			Illiquid future coal prices (per Ton)	U.S.$14 - U.S.$17
Unit contingent power sales	(2)	Black-Scholes	Illiquid commodity forward price volatilities	43 - 52 per cent

(1) A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.

Description	Effects on fair values as at Dec. 31, 2013	Valuation Technique	Unobservable input	Range
Unit contingent power purchases	43	Historical bootstrap	Price discount	0 - 2 per cent
			Volumetric discount[1]	0 - 14 per cent
Long-term power sale	225	Long-term price forecast	Illiquid future power prices (per MW)	$34.40 - $90.83
Coal supply revenue sharing	(12)	Black-Scholes	Volumes (MWh)	18 - 25 per cent of available generation
			Illiquid future implied volatilities in MidC power	35 per cent
Unit contingent power sales	(5)	Black-Scholes	Illiquid commodity forward price volatilities	55 per cent

(1) A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.

The effects on fair values of significant unobservable inputs exclude the effects of observable inputs such as liquidity and credit discounts.

II. Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments 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 the Energy Trading and Generation business segments.

The following tables summarize the key factors impacting the fair value of energy trading risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2014 and 2013, 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, 2013	-	(66)	55	-	14	11	-	(52)	66
Changes attributable to:									
Market price changes on existing contracts	**-**	**(14)**	**113**	**-**	**(5)**	**16**	**-**	**(19)**	**129**
Market price changes on new contracts	**-**	**(1)**	**-**	**-**	**(12)**	**17**	**-**	**(13)**	**17**
Contracts settled	**-**	**14**	**(1)**	**-**	**18**	**(41)**	**-**	**32**	**(42)**
Net risk management assets (liabilities) Sept. 30, 2014	**-**	**(67)**	**167**	**-**	**15**	**3**	**-**	**(52)**	**170**
Additional Level III information:									
Gains recognized in OCI			113			-			113
Total gains included in earnings before income taxes			1			33			34
Unrealized losses included in earnings before income taxes relating to net assets held at Sept. 30, 2014			-			(8)			(8)

	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, 2012	-	(63)	3	(1)	79	28	(1)	16	31
Changes attributable to:									
Market price changes on existing contracts	-	(25)	(5)	-	3	13	-	(22)	8
Market price changes on new contracts	-	(3)	(31)	-	3	(11)	-	-	(42)
Contracts settled	-	8	-	3	(50)	(10)	3	(42)	(10)
Transfers out of Level III(1)	-	-	-	-	28	(28)	-	28	(28)
Net risk management assets (liabilities) at Sept. 30, 2013	-	(83)	(33)	2	63	(8)	2	(20)	(41)
Additional Level III information:									
Losses recognized in OCI			(36)			-			(36)
Total gains included in earnings before income taxes			-			2			2
Unrealized losses included in earnings before income taxes relating to net assets held at Sept. 30, 2013			-			(8)			(8)

(1) The trade terms of these contracts were originally beyond a liquid trading period where forward price forecasts were not available for the full period of the contract. During the period, the contract terms were determined to be within a liquid trading period where observable prices are available.

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 trading transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks.

The following tables summarize the key factors impacting the fair value of other risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2014 and 2013, 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 at Dec. 31, 2013	-	26	-	-	1	-	-	27	-
Changes attributable to:									
Market price changes on existing contracts	**-**	**30**	**-**	**-**	**-**	**-**	**-**	**30**	**-**
Market price changes on new contracts	**-**	**27**	**-**	**-**	**3**	**-**	**-**	**30**	**-**
Contracts settled	**-**	**(11)**	**-**	**-**	**-**	**-**	**-**	**(11)**	**-**
Net risk management assets at Sept. 30, 2014	**-**	**72**	**-**	**-**	**4**	**-**	**-**	**76**	**-**

	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, 2012	-	(50)	-	-	1	-	-	(49)	-
Changes attributable to:									
Market price changes on existing contracts	-	31	-	-	-	-	-	31	-
Market price changes on new contracts	-	1	-	-	2	-	-	3	-
Contracts settled	-	9	-	-	(1)	-	-	8	-
Net risk management assets (liabilities) at Sept. 30, 2013	-	(9)	-	-	2	-	-	(7)	-

IV. Other Financial Assets and Liabilities

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

	Fair value				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value**
Long-term debt(1) - Sept. 30, 2014	**-**	**4,234**	**-**	**4,234**	**4,064**
Long-term debt(1) - Dec. 31, 2013	-	4,367	-	4,367	4,262

(1) Includes current portion and excludes $62 million (Dec. 31, 2013 - $60 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 book value of other short-term financial assets and liabilities (cash and cash equivalents, 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

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 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. Refer to note 9(B) for Level III fair valuation techniques used. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss), and a reconciliation of changes during the period are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2014	2013	**2014**	2013
Unamortized net gain at beginning of period	**165**	5	**160**	5
New inception gains	**7**	174	**16**	173
Amortization recorded in net earnings during the period	**6**	(1)	**2**	-
Unamortized net gain at end of period	**178**	178	**178**	178

10. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	Sept. 30, 2014					Dec. 31, 2013 (Restated)*
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	-	3	-	69	72	99
Long-term	-	192	-	7	199	101
Total energy trading risk management assets	-	195	-	76	271	200
Other						
Current	3	46	-	8	57	14
Long-term	-	24	6	1	31	15
Total other risk management assets	3	70	6	9	88	29
Risk management liabilities						
Energy trading						
Current	-	27	-	31	58	84
Long-term	-	68	-	27	95	102
Total energy trading risk management liabilities	-	95	-	58	153	186
Other						
Current	-	7	-	4	11	1
Long-term	-	-	-	1	1	1
Total other risk management liabilities	-	7	-	5	12	2
Net energy trading risk management assets (liabilities)	-	100	-	18	118	14
Net other risk management assets (liabilities)	3	63	6	4	76	27
Net total risk management assets (liabilities)	3	163	6	22	194	41

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

Hedges

a. Net Investment Hedges

During the second quarter of 2014, following the divestiture described in Note 3, the Corporation de-designated U.S.$180 million of U.S.-denominated debt hedging its net investment in its U.S. operations. Reclassification from accumulated other comprehensive income (loss) ("AOCI") of the cumulative translation adjustment of the disposed foreign operation and the related cumulative net investment hedge amounts have been included in the second quarter gain on disposition. During the third quarter of 2014, the Corporation de-designated an additional U.S.$90 million of U.S.-denominated debt hedging other U.S. operations. This change did not impact earnings or AOCI of the period. Prospectively, the de-designated tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

b. Cash Flow Hedges

During the third quarter of 2014, one of the Corporation's subsidiaries with Australian functional currency became exposed to future payments of JPY5.3 billion for the acquisition of components of property, plant, and equipment over the period to June, 2017. The subsidiary's exposure to foreign exchange fluctuations is hedged using foreign currency forward purchase contracts.

During the second quarter of 2014, the Corporation de-designated a cash flow hedge of the foreign-exchange exposure on a U.S.$20 million debt. No significant reclassifications from AOCI arise as a result of this discontinuation of hedge accounting.

As at Sept. 30, 2014, cumulative gains of $3 million related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

Over the next 12 months ended Sept. 30, 2015, the Corporation estimates that $15 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

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 20(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 Trading Segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

VaR at Sept. 30, 2014 associated with the Corporation's proprietary energy trading activities was $2 million (Dec. 31, 2013 - $2 million).

b. Commodity Price Risk - Generation

The Generation Segment utilizes various commodity contracts and other financial instruments to manage the commodity price risk associated with its electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. VaR at Sept. 30, 2014 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $28 million (Dec. 31, 2013 - $42 million). VaR at Sept. 30, 2014 associated with positions and economic hedges that do not meet hedge accounting requirements was $5 million (Dec. 31, 2013 - $11 million).

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 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 distribution, by credit rating, of certain financial assets as at Sept. 30, 2014:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	88	12	**100**
Risk management assets	100	0	**100**

The Corporation's maximum exposure to credit risk at Sept. 30, 2014, without taking into account collateral held or right of set-off, is represented by the carrying amounts of accounts receivable and risk management assets as per the Condensed Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts.

The maximum credit exposure to any one counterparty for commodity trading operations and hedging, including the fair value of open trading positions, net of any collateral held, at Sept. 30, 2014 was $33 million (Dec. 31, 2013 - $23 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes.

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

	2014	**2015**	**2016**	**2017**	**2018**	**2019 and thereafter**	**Total**
Accounts payable and accrued liabilities	410	-	-	-	-	-	410
Debt(1)	3	714	29	782	758	1,841	4,127
Energy trading risk management (assets) liabilities	5	2	10	3	(4)	(134)	(118)
Other risk management (assets) liabilities	(9)	(39)	(3)	(10)	(15)	-	(76)
Interest on long-term debt(2)	53	178	171	162	125	803	1,492
Dividends payable	55	-	-	-	-	-	55
Total	**517**	**855**	**207**	**937**	**864**	**2,510**	**5,890**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2015 and 2017.

(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 to fall below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Sept. 30, 2014, the Corporation had posted collateral of $86 million (Dec. 31, 2013 - $94 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $82 million (Dec. 31, 2013 - $88 million) of collateral to its counterparties based upon the value of the derivatives at Sept. 30, 2014.

11. PROPERTY, PLANT, AND EQUIPMENT

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

	Land	Thermal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
As at Dec. 31, 2013	77	2,952	912	2,242	578	153	279	7,193
Additions	**-**	**4**	**-**	**-**	**-**	**303**	**17**	**324**
Additions - finance lease	**-**	**-**	**-**	**-**	**16**	**-**	**-**	**16**
Disposals	**-**	**-**	**-**	**(1)**	**-**	**-**	**-**	**(1)**
Asset impairment reversals	**-**	**-**	**1**	**-**	**-**	**-**	**-**	**1**
Depreciation	**-**	**(203)**	**(77)**	**(74)**	**(40)**	**-**	**(9)**	**(403)**
Revisions and additions to decommissioning and restoration costs	**-**	**14**	**5**	**-**	**3**	**-**	**-**	**22**
Retirement of assets	**-**	**(9)**	**(1)**	**(2)**	**(1)**	**-**	**-**	**(13)**
Change in foreign exchange rates	**1**	**17**	**3**	**4**	**-**	**(2)**	**2**	**25**
Transfers	**2**	**121**	**43**	**18**	**9**	**(193)**	**(2)**	**(2)**
As at Sept. 30, 2014	**80**	**2,896**	**886**	**2,187**	**565**	**261**	**287**	**7,162**

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

During the third quarter of 2014, the Corporation evaluated the recoverable amount of its cash-generating units for asset and goodwill impairment testing purposes, and found no significant impairment charges or reversals. The valuations incorporated the most current future power price assumptions available at the time of the valuation for assets with merchant capacity. Following Sept. 30, 2014, decreases in future power prices have been noted in the main markets in which the Corporation operates. These decreases have not been reflected into the valuations. The Corporation's U.S. Coal assets, which have previously been impaired, are particularly sensitive to future power price fluctuations. The Corporation will continue to monitor changes in future power prices as it pertains to asset impairment over the fourth quarter.

12. LONG-TERM DEBT

A. Debt and Letters of Credit

The amounts outstanding are as follows:

As at	**Sept. 30, 2014**			Dec. 31, 2013		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**336**	**335**	**1.9%**	852	852	2.6%
Debentures	**1,042**	**1,051**	**6.1%**	1,269	1,251	6.1%
Senior notes[3]	**2,350**	**2,340**	**4.9%**	1,797	1,809	5.6%
Non-recourse[4]	**378**	**381**	**5.9%**	376	380	5.9%
Other	**20**	**20**	**6.0%**	28	28	6.3%
	4,126	**4,127**		4,322	4,320	
Less: recourse current portion	**(560)**	**(560)**		(209)	(209)	
Less: non-recourse current portion	**(156)**	**(156)**		-	-	
Total long-term debt	**3,410**	**3,411**		4,113	4,111	

(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. Includes U.S.$300 million at Sept. 30, 2014 (Dec. 31, 2013 - U.S.$300 million).

(3) U.S. face value at Sept. 30, 2014 - U.S.$2.1 billion (Dec. 31, 2013 - U.S.$1.7 billion).

(4) Includes U.S.$20 million at Sept. 30, 2014 (Dec. 31, 2013 - U.S.$20 million).

During the second quarter, the Corporation's 6.45 per cent medium term notes matured and were paid out in the amount of $200 million. The remaining Debentures bear interest at fixed rates ranging from 5.00 per cent to 7.30 per cent and have maturity dates ranging from 2019 to 2030.

In June 2014, the Corporation issued U.S.$400 million of senior notes due in 2017 that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes.

As at Sept. 30, 2014, TransAlta had a total of $2.1 billion (Dec. 31, 2013 - $2.1 billion) of committed credit facilities and bilateral credit facilities, of which $1.4 billion (Dec. 31, 2013 - $0.9 billion) was not drawn, and was available, subject to customary borrowing conditions.

The total outstanding letters of credit as at Sept. 30, 2014 was $363 million (Dec. 31, 2013 - $370 million) with no (Dec. 31, 2013 - nil) amounts exercised by third parties under these arrangements. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business.

B. Restrictions

Debt agreements of $1 million related to the Windsor plant, owned by the Corporation's TransAlta Cogeneration L.P. subsidiary, include principal and interest funding provisions that restrict the Corporation's ability to access funds generated by the operations of the plant. The Corporation has provided a letter of credit in the amount of the funding requirements, thereby permitting it to access the funds.

Debentures of $343 million issued by the Corporation's Canadian Hydro Developers, Inc. subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewables assets.

13. COMMON SHARES

A. Issued and Outstanding

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

	3 months ended Sept. 30				9 months ended Sept. 30			
	2014		2013		**2014**		2013	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount	**Common shares** *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**271.8**	**2,962**	262.1	2,836	**268.2**	**2,916**	254.7	2,730
Issued under the dividend reinvestment and optional common share purchase plan	**1.6**	**19**	4.2	55	**5.2**	**65**	11.6	161
	273.4	**2,981**	266.3	2,891	**273.4**	**2,981**	266.3	2,891
Amounts receivable under Employee Share Purchase Plan	**-**	**(2)**	-	(4)	**-**	**(2)**	-	(4)
Issued and outstanding, end of period	**273.4**	**2,979**	266.3	2,887	**273.4**	**2,979**	266.3	2,887

B. Dividends

The following table summarizes the common share dividends declared or paid within the nine months ended Sept. 30:

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares
2014					
July 22, 2014	Oct. 1, 2014	0.18	49	30	19
Apr. 28, 2014	July 1, 2014	0.18	49	30	19
Feb. 20, 2014	Apr. 1, 2014	0.18	48	31	17
Oct. 30, 2013	Jan. 1, 2014	0.29	78	50	28
2013					
July 23, 2013	Oct. 1, 2013	0.29	77	51	26
Apr. 22, 2013	June 28, 2013	0.29	76	21	55
Jan. 28, 2013	Apr. 1, 2013	0.29	75	22	53
Oct. 24, 2012	Jan. 1, 2013	0.29	73	20	53

On Oct. 29, 2014, the Corporation declared a quarterly dividend of $0.18 per common share, payable on Jan. 1, 2015.

On Oct. 1, 2014, 1.6 million common shares were issued for dividends reinvested.

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

B. Earnings Per Share

In calculating earnings per share for the three and nine months ended Sept. 30, 2014, net earnings attributable to common shareholders has been reduced by the Series G cumulative preferred dividends of $1 million (see Note 14).

14. PREFERRED SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

On Aug. 15, 2014, TransAlta completed a public offering of 6.6 million Series G Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $165 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.325 per share as approved by the Board of Directors, payable quarterly, yielding 5.30 per cent per annum, for the initial period ending Sept. 30, 2019. The dividend rate will reset on Sept. 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.80 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends.

The Series G preferred shareholders have the right at their option to convert their shares into Series H Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2019 and on Sept. 30 of every fifth year thereafter. The holders of Series H preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill yield plus 3.80 per cent

At Sept. 30, 2014 and Dec. 31, 2013, the Corporation had 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E Cumulative Redeemable Rate Reset First Preferred shares, issued and outstanding. At Sept. 30, 2014 the Corporation also had 6.6 million (Dec. 31, 2013 – nil) Series G Cumulative Redeemable Rate Reset First Preferred shares, issued and outstanding.

B. Dividends

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

		Series A		**Series C**		**Series E**	
Date declared	**Payment date**	**Dividend per share** *($)*	**Total dividends**	**Dividend per share** *($)*	**Total dividends**	**Dividend per share** *($)*	**Total dividends**
2014							
July 22, 2014	Sept. 30, 2014	0.2875	3	0.2875	4	0.3125	2
Apr. 28, 2014	June 30, 2014	0.2875	4	0.2875	3	0.3125	3
Feb. 20, 2014	March 31, 2014	0.2875	3	0.2875	3	0.3125	3
2013							
July 23, 2013	Sept. 30, 2013	0.2875	3	0.2875	4	0.3125	2
Apr. 22, 2013	June 30, 2013	0.2875	4	0.2875	3	0.3125	3
Jan. 28, 2013	March 31, 2013	0.2875	3	0.2875	3	0.3125	3

As at Sept. 30, 2014, cumulative preferred dividends of $1 million have not been recognized on the recently issued Series G preferred shares (Dec. 31, 2013 - nil).

On Oct. 29, 2014, the Corporation declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.501 per share on the Series G preferred shares all payable Dec. 31, 2014.

15. COMMITMENTS

During the third quarter of 2014, the Corporation announced that it had completed contracting, to build and operate an AUD$570 million, 150 megawatt combined cycle gas power station in South Hedland, Western Australia. The fully contracted power station is expected to be commissioned and delivering power to customers in the first half of 2017. As at Sept. 30, 2014, the Corporation had entered into minimum commitments of AUD$42 million under this project.

At Sept. 30, 2014, the Corporation has remaining commitments for $33 million related to construction of a new natural gas pipeline in Australia. This amount is expected to be spent within the next six months.

During the second quarter of 2014, the Corporation entered into a new fixed price natural gas purchase contract for its own use, in the amount of $27 million, expiring in 2016.

16. 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.

17. SEGMENT DISCLOSURES

A. Reported Segment Earnings (Loss)

3 months ended Sept. 30, 2014	Generation	Energy Trading	Corporate	Total
Revenues	636	3	-	639
Fuel and purchased power	277	-	-	277
Gross margin	359	3	-	362
Operations, maintenance, and administration	113	9	16	138
Depreciation and amortization	128	-	7	135
Asset impairment reversals	(1)	-	-	(1)
Taxes, other than income taxes	6	-	1	7
Intersegment cost allocation	3	(3)	-	-
Operating income (loss)	110	(3)	(24)	83
Finance lease income	12	-	-	12
Net interest expense				(64)
Earnings before income taxes				31

3 months ended Sept. 30, 2013 *(Restated - Note 2(A))*	Generation	Energy Trading	Corporate	Total
Revenues	601	22	-	623
Fuel and purchased power	265	-	-	265
Gross margin	336	22	-	358
Operations, maintenance, and administration	103	9	16	128
Depreciation and amortization	118	-	6	124
Asset impairment reversals	(18)	-	-	(18)
Restructuring provision	(1)	-	-	(1)
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	4	(4)	-	-
Operating income (loss)	123	17	(22)	118
Finance lease income	11	-	-	11
Equity income	2	-	-	2
Sundance Units 1 and 2 return to service	(15)	-	-	(15)
Net interest expense				(65)
Foreign exchange loss				(6)
Earnings before income taxes				45

9 months ended Sept. 30, 2014	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,829**	**76**	**-**	**1,905**
Fuel and purchased power	**824**	**-**	**-**	**824**
Gross margin	**1,005**	**76**	**-**	**1,081**
Operations, maintenance, and administration	**329**	**36**	**39**	**404**
Depreciation and amortization	**382**	**-**	**20**	**402**
Asset impairment reversals	**(1)**	**-**	**-**	**(1)**
Taxes, other than income taxes	**20**	**-**	**1**	**21**
Intersegment cost allocation	**10**	**(10)**	**-**	**-**
Operating income (loss)	**265**	**50**	**(60)**	**255**
Finance lease income	**36**	**-**	**-**	**36**
Gain on sale of assets	**1**	**-**	**-**	**1**
California claim	**-**	**(5)**	**-**	**(5)**
Insurance recovery	**2**	**-**	**-**	**2**
Net interest expense				**(192)**
Foreign exchange loss				**(7)**
Earnings before income taxes				**90**

9 months ended Sept. 30, 2013 *(Restated - Note 2(A))*	Generation	Energy Trading	Corporate	Total
Revenues	1,652	53	-	1,705
Fuel and purchased power	669	-	-	669
Gross margin	983	53	-	1,036
Operations, maintenance, and administration	308	23	45	376
Depreciation and amortization	365	-	17	382
Asset impairment reversals	(18)	-	-	(18)
Restructuring provision	(2)	-	(1)	(3)
Taxes, other than income taxes	22	-	-	22
Intersegment cost allocation	11	(11)	-	-
Operating income (loss)	297	41	(61)	277
Finance lease income	34	-	-	34
Equity loss	(5)	-	-	(5)
Sundance Units 1 and 2 return to service	(15)	-	-	(15)
Gain on sale of assets	-	-	10	10
Net interest expense				(190)
Foreign exchange loss				(2)
Loss on assumption of pension obligations				(29)
Earnings before income taxes				80

Included in the Generation Segment results for the three and nine months ended Sept. 30, 2014 are $4 million (Sept. 30, 2013 - $4 million) and $15 million (Sept. 30, 2013 - $16 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

B. Selected Condensed Consolidated Statements of Financial Position Information

Total segment assets	**Generation**	**Energy Trading**	**Corporate**	**Total**
Sept. 30, 2014	**8,915**	**162**	**491**	**9,568**
Dec. 31, 2013 *(Restated - Note 2(A))*	9,093	244	287	9,624

C. 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 and the Condensed Consolidated Statements of Cash Flows is presented below:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2014	2013	**2014**	2013
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**135**	124	**402**	382
Depreciation included in fuel and purchased power	**13**	16	**41**	42
Other	**-**	1	**-**	1
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**148**	141	**443**	425

SUPPLEMENTAL INFORMATION

		Sept. 30, 2014	Dec. 31, 2013[1]
Closing market price (TSX) ($)		**11.75**	13.48
Price range for the last 12 months (TSX) ($)	High	**14.94**	16.86
	Low	**11.54**	12.91
Debt to invested capital (%)		**57.6**	60.6
Debt to invested capital excluding non-recourse debt[2] (%)		**55.4**	58.6
Debt to invested capital including finance lease obligation and non-recourse debt (%)		**57.8**	60.8
Debt to comparable EBITDA[3] (times)		**4.5**	4.6
Return on equity attributable to common shareholders[3] (%)		**(3.4)**	(3.2)
Comparable return on equity attributable to common shareholders[2, 3] (%)		**1.1**	3.7
Return on capital employed[3] (%)		**2.7**	2.8
Comparable return on capital employed[2, 3] (%)		**4.2**	5.1
Cash dividends per share[3] ($)		**0.94**	1.16
Price to comparable earnings ratio[2, 3] (times)		**146.9**	43.5
Earnings coverage[3] (times)		**0.8**	0.8
Dividend payout ratio based on net earnings[3] (%)		**(308.2)**	(431.0)
Dividend payout ratio based on comparable earnings[2, 3] (%)		**978.3**	377.8
Dividend payout ratio based on funds from operations[2, 3, 4] (%)		**32.3**	43.1
Dividend yield[3] (%)		**8.0**	8.6
Adjusted cash flow to debt[3, 4] (%)		**15.8**	15.0
Adjusted cash flow to interest coverage[3, 4] (times)		**3.7**	3.7

(1) Prior year figured have been restated to conform to the current year's presentation.

(2) 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 this calculation, refer to the Non-IFRS Measures section of this MD&A.

(3) Last 12 months.

(4) The December 2013 ratios have been adjusted for the impact of the California claim.

RATIO FORMULAS

Debt to invested capital = long-term debt including current portion + 50 per cent issued preferred shares - cash and cash equivalents / long-term debt including current portion + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares - cash and cash equivalents

Debt to comparable EBITDA = long-term debt including current portion - 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 AOCI

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

Price to comparable earnings ratio = current period's closing market price / comparable earnings per share

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 = common share dividends / net earnings attributable to common shareholders or earnings on a comparable basis or funds from operations - 50 per cent dividends paid on preferred shares

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

Adjusted cash flow to debt = cash flow from operating activities before changes in working capital - 50 per cent dividends paid on preferred shares/ total debt + 50 per cent issued preferred shares - cash and cash equivalents

Adjusted cash flow to interest coverage = cash flow from operating activities before changes in working capital + 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 “major 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.

Heat Rate - A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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.

Renewable Power - Power generated from renewable terrestrial mechanisms including wind, geothermal, and solar with regeneration.

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

Value at Risk (VaR) - A measure to manage earnings exposure from energy trading activities.

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