TRANSALTA CORPORATION
NEWS RELEASE

TransAlta achieves annual availability targets for 2012, announces fourth quarter and files year end disclosure documents

HIGHLIGHTS

- Adjusted fleet availability was in line with our annual target of 89 to 90 per cent at 89.4 per cent for the quarter and 90.0[1] per cent for the year
- Comparable EBITDA[2,3,4] increased to $310 million for the quarter up $43 million from the same period in 2011 driven by solid results from generation and a full quarter contribution from the Solomon acquisition; Comparable EBITDA for the full year was $1,014 million
- Operations, Maintenance and Administration ("OM&A") declined 10 per cent year over year, or $52 million, compared to our target reduction of 5 per cent
- Energy Trading delivered $13 million of gross margin in the fourth quarter, and $3 million for the year
- Funds From Operations[3,4] increased to $205 million for the quarter up $16 million from the same period in 2011; Funds From Operations for the full year were $776 million

CALGARY, Alberta (Feb. 27, 2013) – TransAlta Corporation ("TransAlta") (TSX: TA; NYSE: TAC) today reported 2012 fourth quarter comparable earnings of $54 million ($0.21 per share) up from $29 million ($0.13 per share) in the fourth quarter of 2011. Net earnings attributable to common shareholders for the fourth quarter of 2012 were $38 million ($0.15 per share).

The increase in comparable earnings for 2012 was driven by strong fleet availability, the addition of the Solomon acquisition and lower OM&A costs, partially offset by higher planned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities, Genesee Unit 3 and lower Energy Trading results. Fourth quarter 2012 net earnings were lower than comparable earnings primarily due to the impact of de-designation of hedges and corporate realignment charges incurred to reposition TransAlta for strategic growth.

"TransAlta's fourth quarter has shown promising gains," said Dawn Farrell, TransAlta President and CEO. "This return to more normalized results is a positive step in the right direction and a good starting point for 2013. 2012 marked a year of substantial progress for TransAlta. We have stayed the course and completed what we said we would do, including setting the fleet up for end of life and realigning the company to ensure continuous focus on operational excellence and growth. These efforts will carry forward into the future and are expected to reduce costs by approximately $25 to $30 million on an annualized basis by the end of 2013."

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(1) Adjusted for economic dispatching at Centralia.

(2) EBITDA refers to Earnings before interest, taxes, depreciation and amortization.

(3) Comparable earnings (loss), comparable earnings (loss) per share, comparable EBITDA, and funds from operations, are not defined under International Finance Reporting Standards ("IFRS"). Presenting these measures from period to period provides supplemental information to help management and shareholders evaluate earnings' trends in comparison with prior periods' results. Refer to the Non-IFRS Measures section of the Management's Discussion and Analysis ("MD&A") for further discussion of these items, including, where applicable, reconciliations to net earnings (loss) attributable to common shareholders, operating income (loss), and cash flow from operating activities.

(4) Comparable EBITDA and funds from operations are key supplemental performance measures for TransAlta which provide additional information regarding the company's ability to cover its capital requirements and dividends as well as strengthen its balance sheet and finance growth.

Consistent strength maintained in Generation performance

Fleet availability for the quarter remained strong at 89.4 per cent compared to 90.3 per cent in the fourth quarter of 2011. The marginal decrease in availability is primarily attributable to higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3, partially offset by lower unplanned outages at the Alberta coal PPA facilities and Genesee Unit 3.

Improvement in EBITDA and cash flow in the quarter

Comparable EBITDA improved $43 million in the fourth quarter to $310 million, compared to $267 million for the same period in 2011. Funds from operations increased $16 million in the fourth quarter to $205 million, compared to $189 million for the same period in 2011. These increases were driven by solid results in Generation, the addition of Solomon to the fleet, and lower OM&A costs, which more than offset lower trading margins.

TRANSALTA 2012 FULL YEAR RESULTS

TransAlta reported full year comparable earnings of $118 million ($0.50 per share) versus $230 million ($1.04 per share) in 2011. Comparable results for the year were driven by strong availability across the fleet, but were more than offset by significantly lower Energy Trading gross margins, which were down $134 million from 2011 as well as higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3.

The net loss attributable to common shareholders for the year was $614 million ($2.61 per share) compared to net earnings of $290 million ($1.31 per share) in 2011. This loss is largely due to asset impairment charges of $226 million incurred from writing down the carrying value of the Centralia Plant under IFRS, a write off of $169 million of deferred tax assets, and the one-time impact of $189 million based on the Alberta arbitration panel’s decision on Sundance Units 1 and 2, outlined in our press release of July 23, 2012.

Strong Generation performance; TransAlta delivers on its fleet availability goal of 89 - 90 per cent for the year

Adjusted fleet availability for the full year was 90.0 per cent, up from 88.2 per cent in 2011 in spite of six major planned coal outages to complete the three-year investment program. Adjusted fleet availability increased as a result of lower planned and unplanned outages at the Centralia Plant and lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3.

TransAlta maintains stable cash flow for the year

Funds from operations for the year were $776 million versus $809 million in 2011, down due to lower cash earnings which can be largely attributed the decrease in Energy Trading gross margins, partially offset by an increase in Generation gross margins, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings.

Highlights - 2012

Financial

- Comparable EBITDA of $1,014 million
- Funds from operations of $776 million or $3.30 per share
- Comparable earnings of $118 million or $0.50 per share
- Dividends paid of $1.16 per share to common shareholders
- Approximately 70 per cent participation in our dividend reinvestment plan, resulting in an estimated annualized cash savings of approximately $210 million

Operating

- Coal: Comparable gross margins from TransAlta's coal fleet increased $20 million year-over-year despite higher planned outages
- Gas: Comparable gross margins from TransAlta's gas fleet increased $21 million year-over-year as a result of strong availability and reduced gas input costs
- Renewables: Comparable gross margins increased $4 million year-over-year primarily due to strong hydro generation outpacing lower prices in Alberta and lower wind volumes in Western and Eastern Canada
- Energy Trading: Gross margins decreased $134 million year-over-year due to unfavorable market conditions relative to trading positions held

Major maintenance

- TransAlta completed its three-year intensive major maintenance program for its coal fleet. Completion of this capital investment program sets up these coal units to operate to end of life.

Growth

- Acquisition of the 125 megawatt ("MW") dual-fuel Solomon power station for U.S. $318 million, which is fully contracted with Fortescue Metals Group Ltd.
- TransAlta and MidAmerican Energy Holdings Company entered into a new strategic partnership through which the two companies will work together to develop, build, and operate new natural gas-fired electricity generation projects in Canada
- Construction of the 68 MW contracted New Richmond wind farm in Quebec is on track to be commissioned in the first quarter of 2013
- Realignment of resources as part of an ongoing strategy to continuously improve operational excellence and accelerate growth, resulting in $25 - $30 million cost savings per year by the end of 2013

Significant Events

Sundance Unit 3

On November 23, 2012, TransAlta reported that the independent arbitration panel granted TransAlta force majeure relief for derates and outages in 2012 and 2011 related to the mechanical failure of critical generator components on Sundance Unit 3. This decision validates that the mechanical failure was beyond TransAlta's reasonable control.

Federal Greenhouse gas regulations

As a result of amendments to Canadian federal regulations requiring coal-fired plants be shut down after a maximum of 50 years of operation, TransAlta has reviewed the useful lives of the Alberta coal generating facilities and related coal mining assets, and where permitted under the regulations, extended the useful lives to a maximum of 50 years.

Sundance Units 1 and 2

On July 23, 2012, TransAlta reported the independent arbitration panel considering TransAlta's decision in December 2010 to shut down two units at its Sundance generating station had allowed the company's claim of force majeure. This decision validates TransAlta's belief the units failed due to issues beyond its control.

TransAlta also sought to have the PPA terminated for economic reasons, as provided for under the legislation. The panel did not agree with this claim. The cost to repair the units is estimated at approximately $190 million. This investment is expected to start generating cash flow in the fourth quarter of 2013.

Net penalties of $189 million from the arbitration panel's decision were recorded in the second quarter of 2012. Additionally, TransAlta wrote down its Sundance Units 1 and 2 by $43 million in the second quarter. This impairment was reversed by $41 million in the third quarter as a result of additional years of merchant operations expected to be realized due to the amendments to Canadian federal regulations.

TransAlta files year end disclosure documents

TransAlta also announced today it has filed its Annual Information Form, Audited Consolidated Financial Statements and accompanying notes, as well as the MD&A. These documents are available through TransAlta's website at www.transalta.com or through Sedar at www.sedar.com.

TransAlta has also filed its 40-F with the U.S. Securities and Exchange Commission. The form is available through their website at www.sec.gov. Paper copies of all documents are available to shareholders free of charge upon request.

A complete copy of TransAlta's fourth quarter extended news release is available in the Investors Centre section of our website: www.transalta.com.

TransAlta will hold a conference call and live webcast and presentation at 9 a.m. MT (11 a.m. ET) today to discuss results. The call will begin with a short address by Dawn Farrell, President and CEO, and Brett Gellner, Chief Financial Officer, followed by a question and answer period for investment analysts, investors, and other interested parties. A question and answer period for the media will immediately follow.

Please contact the conference operator five minutes prior to the call, noting "TransAlta Corporation" as the company and "Brent Ward" as moderator.

Fourth Quarter and 12 Months Ended Dec. 31 2012 Highlights:

In millions, unless otherwise stated	3 months ended Dec. 31, 2012	3 months ended Dec. 31, 2011	12 months ended Dec. 31, 2012	12 months ended Dec. 31, 2011
Availability adjusted for Centralia (%)	89.4	90.3	90.0	88.2
Production (GWh)	10,880	11,662	38,750	41,012
Revenue	661	701	2,262	2,663
Gross margin(1)	398	409	1,453	1,716
Operating income(1)	132	122	42	645
Net earnings (loss) attributable to common shareholders	38	24	(614)	290
Comparable earnings(2)	54	29	118	230
Basic and diluted earnings (loss) per common share	0.15	0.11	(2.61)	1.31
Comparable earnings per share(2)	0.21	0.13	0.50	1.04
Comparable EBITDA(2)	310	267	1,014	1,045
Funds from operations(2)	205	189	776	809
Funds from operations per share(2)	0.80	0.84	3.30	3.64
Cash flow from operations	245	187	520	690

Dial-in numbers:

Toll-free North American participants call: 1-800-319-4610

Outside of Canada & USA call: 1-604-638-5340

A link to the live webcast will be available on the Investor Centre section of TransAlta's website at http://www.transalta.com/investor-centre/events-presentations/webcasts-conference-calls. If you are unable to participate in the call, the instant replay is accessible at 1-604-638-9010 with TransAlta pass code 2231 followed by the # sign. A transcript of the broadcast will be posted on TransAlta's website once it becomes available.

Note: If using a hands-free phone, lift the handset and press one to ask a question.

TransAlta is a power generation and wholesale marketing company focused on creating long-term shareholder value. TransAlta maintains a low-to-moderate risk profile by operating a highly contracted portfolio of assets in Canada, the United States and Australia. TransAlta's focus is to efficiently operate geothermal, wind, hydro, natural gas and coal facilities in order to provide customers with a reliable, low-cost source of power. For over 100 years, TransAlta has been a responsible operator and a proud contributor to the communities in which it works and lives. TransAlta has been selected by Jantzi-Sustainalytics as one of Canada's Top 50 Socially Responsible Companies since 2009 and is recognized globally for its leadership on sustainability and corporate responsibility standards by FTSE4Good. TransAlta is Canada's largest investor-owned renewable energy provider.

This news release may contain forward looking statements, including statements regarding the business and anticipated financial performance of TransAlta Corporation. These statements are based on TransAlta Corporation's belief and assumptions based on information available at the time the assumption was made. These statements are subject to a number of risks and uncertainties that may cause actual results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause such differences include legislative or regulatory developments, competition, global capital markets activity, changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta Corporation operates.

Note: All financial figures are in Canadian dollars unless noted otherwise.

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(1) Gross margin and operating income are Additional IFRS measures. Refer to the Additional IFRS measures section of the MD&A.

(2) Comparable earnings, comparable earnings per share, comparable EBITDA, funds from operations, and funds from operations per share are not defined under IFRS. Refer to the Non-IFRS financial measures section of the MD&A for an explanation and, where applicable, reconciliations to net earnings(loss) attributable to common shareholders, operating income (loss) and cash flow from operating activities.

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BASIS OF PRESENTATION

This news release should be read in conjunction with our 2012 audited consolidated financial statements and 2012 Annual Management's Discussion and Analysis ("MD&A"). In this news release, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. 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. In this news release, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Consolidated Statements of Earnings (Loss) and Consolidated Statements of Financial Position items. While individual line items in the 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 Consolidated Statements of Financial Position.

HIGHLIGHTS

Generation Results

- Comparable gross margins, excluding finance leases impact, increased $27 million to $394 million quarter over quarter, primarily due to the impact of lower Alberta coal Power Purchase Arrangement ("PPA") penalties due to lower prices in Alberta and higher hydro margins, partially offset by higher coal costs.
- Total finance lease income increased $9 million in the quarter due to the new Solomon finance lease.
- Overall fleet availability decreased almost one per cent to 89.4 per cent due to higher planned outages at the PPA facilities and higher unplanned outages at Centralia Thermal.
- Through continued efforts to lower costs and focus on productivity, comparable Operations, Maintenance, and Administration ("OM&A") costs have been reduced by $17 million to $92 million.

Energy Trading Results

- Gross margins decreased $27 million to a gross margin of $13 million for the quarter, primarily due to unfavorable market expectations on power and gas prices for our trading positions held. Compared to the previous quarter, gross margins increased by $29 million. The total gross margins for the year for Energy Trading were $3 million.
- OM&A costs decreased to $8 million, primarily due to lower compensation costs as a result of lower earnings.

Financial Highlights

- Comparable earnings were $54 million ($0.21 per share), up from $29 million ($0.13 per share) in 2011. The increase in comparable earnings is primarily due to higher earnings in the Generation Segment and OM&A savings, partially offset by lower trading margins. Reported net earnings attributable to common shareholders were $38 million ($0.15 per share), up from $24 million ($0.11 per share) in 2011, which included the following non-comparable amounts, net of tax:
    - Impact of de-designation of hedges of $9 million,
    - Restructuring charges of $10 million, and
    - Inventory writedown of $3 million.
- Comparable Earnings Before Interest, Taxes, Depreciation, and Amortization (“EBITDA”) increased $43 million in the quarter to $310 million compared to 2011.
- Funds from Operations (“FFO”) increased $16 million in the quarter to $205 million.
- A quarterly dividend of $0.29 per share was declared on common shares.

Strategic Partnership

We have created a new strategic partnership with MidAmerican Energy Holdings Company through which the two companies will work together to develop, build, and operate new natural gas-fueled electricity generation projects in Canada.

The following table depicts key financial results and statistical operating data:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Availability (%)[1]	**89.4**	90.3	**88.4**	85.4
Adjusted availability (%)[1],[2]	**89.4**	90.3	**90.0**	88.2
Production (GWh)[1]	**10,880**	11,662	**38,750**	41,012
Revenues	**661**	701	**2,262**	2,663
Gross margin[3]	**398**	409	**1,453**	1,716
Operating income (loss)[3]	**132**	122	**42**	645
Comparable operating income[4]	**165**	126	**470**	553
Net earnings (loss) attributable to common shareholders	**38**	24	**(614)**	290
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.15**	0.11	**(2.61)**	1.31
Comparable net earnings per share[4]	**0.21**	0.13	**0.50**	1.04
Comparable EBITDA[4]	**310**	267	**1,014**	1,045
Funds from operations[4]	**205**	189	**776**	809
Funds from operations per share[4]	**0.80**	0.84	**3.30**	3.64
Cash flow from operating activities	**245**	187	**520**	690
Free cash flow[4]	**31**	9	**85**	185
Dividends paid per common share	**0.29**	0.29	**1.16**	1.16

As at	**Dec. 31, 2012**	Dec. 31, 2011
Total assets	**9,451**	9,729
Total long-term liabilities	**4,726**	4,911

AVAILABILITY & PRODUCTION

Availability for the three months ended Dec. 31, 2012 decreased compared to the same period in 2011 primarily due to higher planned outages at the Alberta coal PPA facilities and at Genesee Unit 3 and higher unplanned outages at Centralia Thermal, partially offset by lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3.

For the year ended Dec. 31, 2012, availability increased compared to the same period in 2011 primarily due to lower planned and unplanned outages at Centralia Thermal and lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and at Genesee Unit 3.

Production for the three months ended Dec. 31, 2012 decreased 782 gigawatt hours ("GWh") compared to the same period in 2011 due to higher planned outages at the Alberta coal PPA facilities and at Genesee Unit 3, higher economic dispatching at Centralia Thermal, lower PPA customer demand, higher planned and unplanned outages at Centralia Thermal, and lower wind volumes, partially offset by lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, and market curtailments.

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

(2) Adjusted for economic dispatching at Centralia Thermal.

(3) These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this news release for further discussion of these items.

(4) These comparable 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 Non-IFRS Measures section of this news release for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

For the year ended Dec. 31, 2012, production decreased 2,262 GWh compared to the same period in 2011 due to higher economic dispatching at Centralia Thermal, higher planned outages at the Alberta coal PPA facilities and at Genesee Unit 3, lower PPA customer demand, and market curtailments, partially offset by lower planned and unplanned outages at Centralia Thermal, the commencement of commercial operations at Keephills Unit 3, lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, and higher hydro volumes.

The outages at Centralia Thermal did not negatively impact our gross margins for the years ended Dec. 31, 2012 and 2011 as we were able to extend some of our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Overall fleet availability, after adjusting for the extended planned outages at Centralia, was 90.0 per cent for the year ended Dec. 31, 2012 (Dec. 31, 2011 - 88.2 per cent).

NET EARNINGS (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings (loss) attributable to common shareholders for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Net earnings attributable to common shareholders, 2011	24	290
Increase in Generation comparable gross margins	27	45
Mark-to-market movements and de-designations - Generation	(16)	(199)
Decrease in Energy Trading gross margins	(27)	(134)
Decrease in operations, maintenance, and administration costs	27	52
Decrease (increase) in depreciation and amortization expense	14	(27)
Decrease in gain on sale of assets	(13)	(13)
Decrease (increase) in asset impairment charges	3	(307)
Increase in inventory writedown, net of consumption	(5)	(19)
Increase in restructuring charges	(13)	(13)
Decrease (increase) in net interest expense	4	(27)
Decrease in equity income	(8)	(29)
Impact of Sundance Units 1 and 2 arbitration	-	(254)
Increase in preferred share dividends	(6)	(16)
MF Global Inc. collateral	18	33
Other	9	4
Net earnings (loss) attributable to common shareholders, 2012	**38**	**(614)**

Generation comparable gross margins, excluding the impact of mark-to-market movements, for the three months ended Dec. 31, 2012 increased compared to the same period in 2011 primarily due to the impact of lower Alberta coal PPA penalties due to lower prices in Alberta, lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, and higher hydro margins, partially offset by higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3 and unfavourable coal costs.

For the year ended Dec. 31, 2012, Generation comparable gross margins, excluding the impact of mark-to-market movements, increased compared to the same period in 2011 primarily due to the impact of lower Alberta coal PPA penalties due to lower prices in Alberta, higher hydro margins, and lower unplanned outages at the Alberta coal PPA facilities and at Genesee Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and Genesee Unit 3, unfavourable coal costs, and market curtailments.

Mark-to-market movements decreased for the three months and year ended Dec. 31, 2012 compared to the same periods in 2011 due to the recognition of higher mark-to-market gains in 2011 resulting from certain power hedging relationships being deemed ineffective. Included in these gains are amounts that are adjusted as a non-comparable item. Please refer to the Non-IFRS Measures section of this news release for further discussion.

For the three months and year ended Dec. 31, 2012, Energy Trading gross margins decreased compared to the same periods in 2011 primarily due to the impact of unexpected weather patterns, plant outages, and unfavourable market expectations on power and gas pricing for trading positions held.

OM&A costs for the three months and year ended Dec. 31, 2012 decreased compared to the same periods in 2011 primarily due to lower compensation costs as a result of productivity initiatives and a continued focus on costs.

Depreciation and amortization expense for the three months ended Dec. 31, 2012 decreased compared to 2011 primarily due to a reduction in depreciation expense due to a lower depreciable asset base caused by asset impairments and the change in the economic useful lives of Alberta coal-fired plants partially offset by an increased asset base.

For the year ended Dec. 31, 2012, depreciation and amortization expense increased compared to 2011 primarily due to an increased asset base, largely due to the commencement of commercial operations at Keephills Unit 3, and asset retirements, partially offset by a reduction in depreciation expense due to a lower depreciable asset base caused by asset impairments and the change in the economic useful lives of Alberta coal-fired plants.

Gain on sale of assets for the three months and year ended Dec. 31, 2012 decreased compared to 2011 due to the sale of our Meridian and Grande Prairie facilities and other development projects in 2011.

Asset impairment charges for the three months ended Dec. 31, 2012 decreased due to recognition of a pre-tax impairment on an asset in the renewables fleet in 2011. The impairment resulted from the completion of the annual impairment assessment based on estimates of fair value less costs to sell, derived from the long-range forecasts and prices evidenced in the marketplace.

For the year ended Dec. 31, 2012, asset impairment charges increased due to the recognition of an impairment charge on the Centralia Thermal plant in 2012 and higher impairments in 2012 compared to 2011 on assets within our renewables fleet, in order to write these assets down to their fair values. The impairment charges can be reversed in future periods if the forecasted cash flows generated by these plants improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

The inventory writedown recorded in the three months and year ended Dec. 31, 2012 of $10 million and $44 million, respectively, is due to a continued low price environment in the Pacific Northwest and the net writedown of coal inventories resulting from de-designation of the hedges at the Centralia Thermal plant. The de-designation prevents us from including these contracts as part of the calculation of the net recoverable amount of the inventory. A $5 million and $36 million benefit for the three months and year ended Dec. 31, 2012, respectively, is reflected in Generation gross margins, resulting from the consumption of previously written down inventories. Of the annual amount, $25 million is considered non-comparable as it relates to inventory that was on hand when the hedges were initially de-designated.

Restructuring charges of $13 million were incurred during 2012 due to a restructuring of our resources that is expected to result in a net reduction of approximately 165 positions as part of our ongoing strategy to continuously improve operational excellence and accelerate growth.

Net interest expense for the three months ended Dec. 31, 2012 decreased compared to the same period in 2011 due to lower interest rates and higher capitalized interest, partially offset by higher ineffectiveness on hedges.

For the year ended Dec. 31, 2012, net interest expense increased compared to 2011 primarily due to lower capitalized interest.

Equity income for the three months ended Dec. 31, 2012 decreased compared to 2011 primarily due to unfavourable pricing at CE Generation, LLC ("CE Gen").

For the year ended Dec. 31, 2012, equity income decreased compared to the same period in 2011 due to higher unplanned outages and unfavourable pricing at CE Gen.

During the second quarter of 2012, results of the Sundance Units 1 and 2 arbitration were released and recorded.

The preferred share dividends for the three months and year ended Dec. 31, 2012 increased compared to the same periods in 2011 due to a higher balance of preferred shares outstanding during 2012.

In 2011, a reserve on collateral of $18 million was taken related to collateral on hand at MF Global Inc. due to the uncertainty of collecting the collateral. During 2012, we sold our claim against MF Global Inc. pertaining to the return of collateral, resulting in a gain of $15 million.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

FFO for the three months ended Dec. 31, 2012 increased $16 million compared to the same period in 2011 primarily due to improved net earnings, which is largely due to the improved results in the Generation Segment and a decrease in OM&A costs, primarily offset by losses in the Energy Trading Segment, after adjusting for non-cash items, primarily unrealized losses from risk management activities.

For the year ended Dec. 31, 2012, FFO decreased $33 million compared to 2011 primarily due to lower net earnings, which is mainly due to the decrease in the gross margin of our Energy Trading Segment and higher planned maintenance in the Generation Segment, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings.

Free cash flow for the three months ended Dec. 31, 2012 increased $22 million compared to the same period in 2011 due to the increase in funds from operations and lower cash dividends paid as a result of increased participation in the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "Plan"), partially offset by higher sustaining capital and productivity expenditures and higher cash dividends paid on preferred shares.

For the year ended Dec. 31, 2012, free cash flow, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings, decreased $100 million compared to 2011 due to the decrease in funds from operations and higher sustaining capital and productivity expenditures, partially offset by lower cash dividends paid as a result of increased participation in the Plan. A significant part of the sustaining capital and productivity expenditures incurred during 2012 relates to more comprehensive planned major maintenance, primarily at Keephills Units 1 and 2, including significant component replacements that are not expected to be replaced again over the balance of the life of the plant.

SUBSEQUENT EVENTS

Centralia Thermal

On July 25, 2012, we announced that we entered into an 11-year agreement to provide electricity from the Centralia Thermal plant to Puget Sound Energy ("PSE"). The contract begins in 2014 and runs until 2025 when the plant is scheduled to be shut down under the TransAlta Energy Bill (the "Bill") that was signed on Dec. 23, 2011. Under the agreement, PSE will buy 180 megawatts ("MW") of firm, base-load power starting in December 2014. In December 2015, the contract increases to 280 MW and from December 2016 to December 2024, the contract is for 380 MW. In the last year of the contract, the contracted volume is 300 MW. The agreement was approved, with conditions, by the Washington Utilities and Transportation Commission ("WUTC") on Jan. 9, 2013. On Jan. 23, 2013, it was announced that PSE has filed a petition for reconsideration of certain conditions within the decision issued by the WUTC. On Feb. 5, 2013, the WUTC granted a 30-day extension to the petition and indicated that it would issue its decision on the petition no later than March 29, 2013.

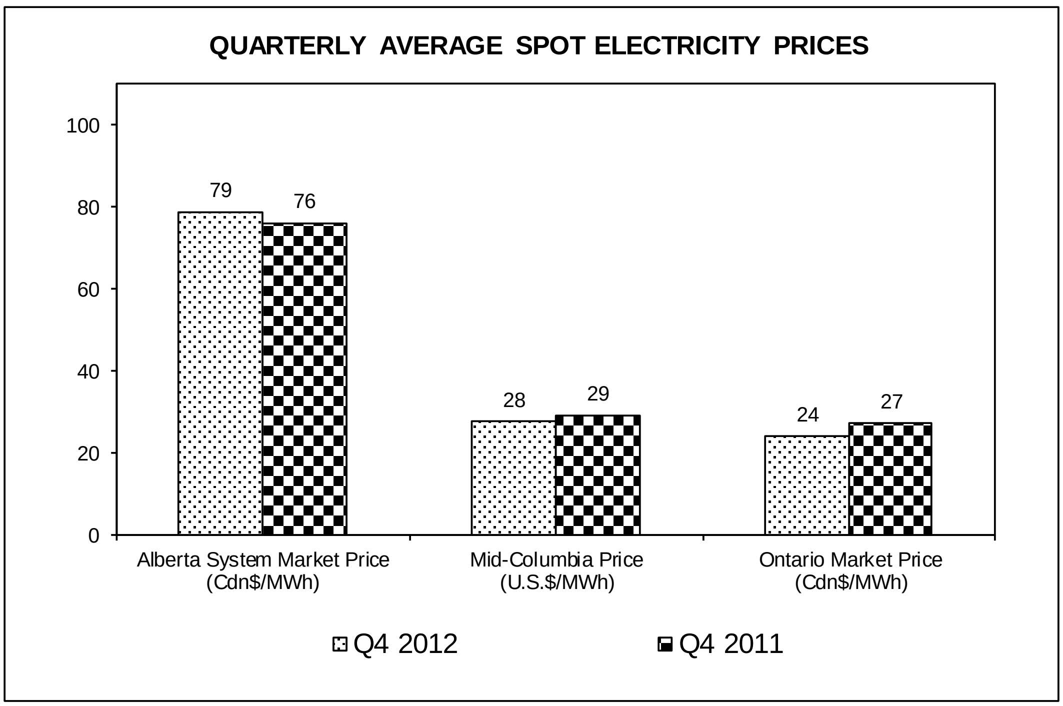
BUSINESS ENVIRONMENT

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 United States ("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 2012 Annual MD&A.

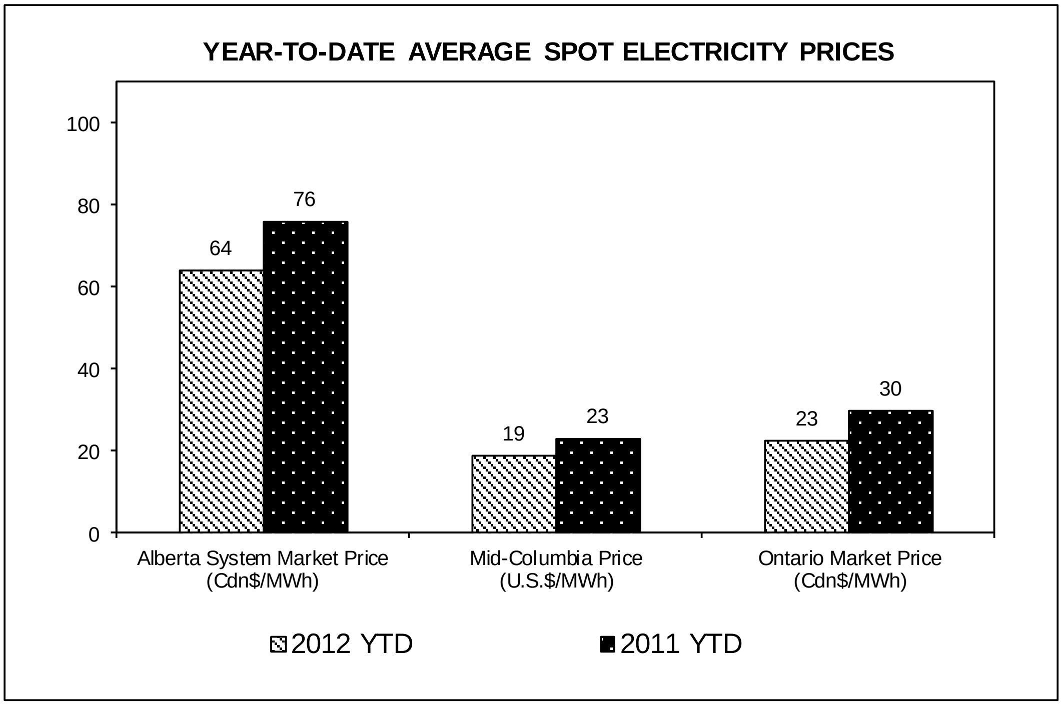
Electricity Prices

Please refer to the Business Environment section of our 2012 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 months and year ended Dec. 31, 2012 and 2011 in our three major markets are shown in the following graphs.



For the three months ended Dec. 31, 2012, average spot prices in Alberta increased compared to the same period in 2011 due to higher demand. In the Pacific Northwest, average spot prices decreased due to lower weather driven demand and increased wind generation. The average spot prices in Ontario decreased compared to 2011 due to lower natural gas prices and increased supply resulting from facilities returning to service from extended outages in the quarter.



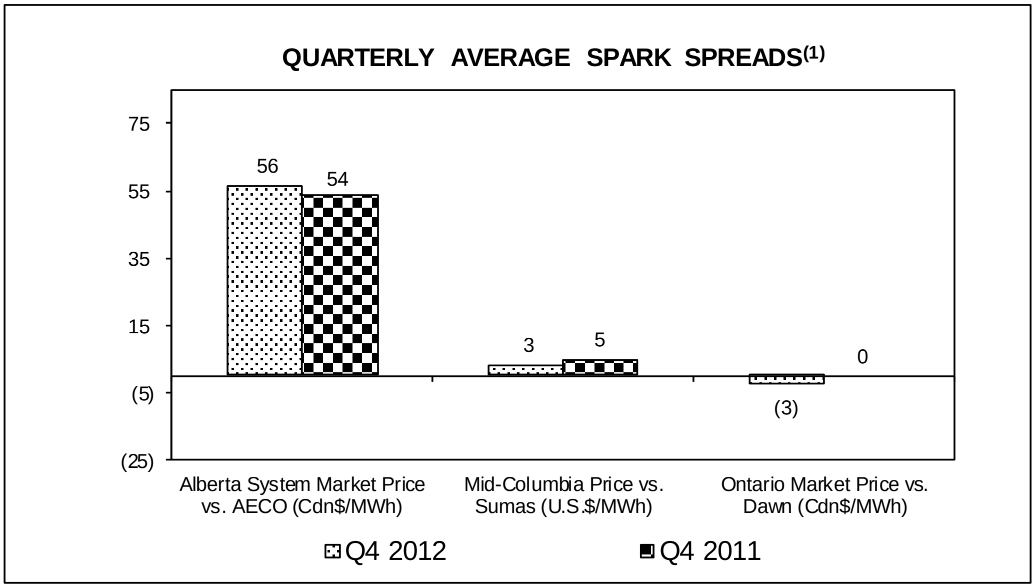
For the year ended Dec. 31, 2012, average spot prices in all three markets decreased compared to the same period in 2011 partially due to lower natural gas prices. In Alberta, spot prices also decreased as a result of overall higher availability. In the Pacific Northwest, spot prices also decreased as a result of increased wind and hydro generation. Spot prices in Ontario also decreased compared to 2011 due to increased supply resulting from facilities returning to service.

In 2013, power prices in Alberta are expected to be lower than 2012 due to fewer planned turnarounds and increased capacity due to additional generation facilities coming online, partially offset by load growth. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, overall prices will still remain weak because of low natural gas prices and slow load growth.

Spark Spreads

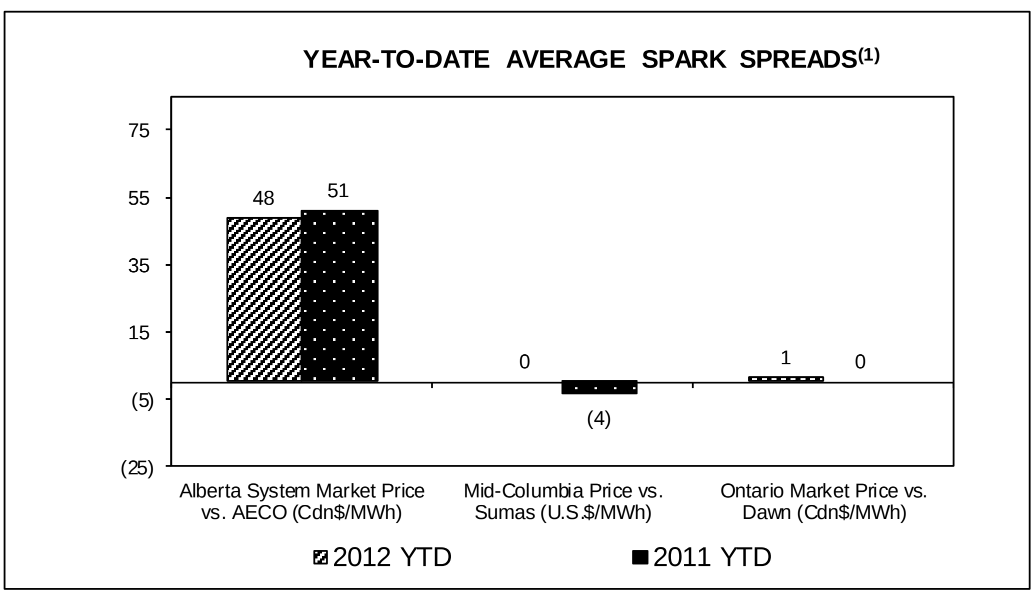
Please refer to the Business Environment section of our 2012 Annual MD&A for a full discussion of spark spreads and the impact of spark spreads on our business.

The average spark spreads for the three months and year ended Dec. 31, 2012 and 2011 in our three major markets are shown in the following graphs.



(1) For a 7,000 British Thermal Units ("Btu") per Kilowatt hour ("KWh") heat rate plant.

For the three months ended Dec. 31, 2012, average spark spreads increased in Alberta compared to the same period in 2011 due to higher power prices. In the Pacific Northwest and Ontario, average spark spreads decreased as a result of lower power prices compared to 2011.



(1) For a 7,000 Btu/KWh heat rate plant.

For the year ended Dec. 31, 2012, average spark spreads in Alberta decreased compared to the same period in 2011 due to lower power prices. In the Pacific Northwest and Ontario, average spark spreads increased as a result of lower natural gas prices compared to 2011. The decrease in natural gas prices was greater than the decrease in spot prices in both the Pacific Northwest and Ontario, causing the spark spread to increase compared to 2011.

DISCUSSION OF SEGMENTED RESULTS

Our operating results by segment are presented below:

3 months ended Dec. 31, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**648**	**13**	**-**	**661**
Fuel and purchased power	**263**	**-**	**-**	**263**
Gross margin	**385**	**13**	**-**	**398**
Operations, maintenance, and administration	**92**	**8**	**18**	**118**
Depreciation and amortization	**114**	**-**	**5**	**119**
Inventory writedown	**10**	**-**	**-**	**10**
Restructuring charges	**5**	**-**	**8**	**13**
Taxes, other than income taxes	**5**	**-**	**1**	**6**
Intersegment cost allocation	**3**	**(3)**	**-**	**-**
Operating income (loss)	**156**	**8**	**(32)**	**132**
Finance lease income	**11**	**-**	**-**	**11**
Equity loss	**(10)**	**-**	**-**	**(10)**
Foreign exchange loss				**(2)**
Net interest expense				**(60)**
Earnings before income taxes				**71**

3 months ended Dec. 31, 2011	Generation	Energy Trading	Corporate	Total
Revenues	661	40	-	701
Fuel and purchased power	292	-	-	292
Gross margin	369	40	-	409
Operations, maintenance, and administration	110	16	19	145
Depreciation and amortization	127	-	6	133
Asset impairment charges	3	-	-	3
Taxes, other than income taxes	6	-	-	6
Intersegment cost allocation	2	(2)	-	-
Operating income (loss)	121	26	(25)	122
Finance lease income	2	-	-	2
Equity loss	(2)	-	-	(2)
Gain on sale of assets	13	-	-	13
Reserve on collateral	-	(18)	-	(18)
Foreign exchange loss				(3)
Net interest expense				(64)
Earnings before income taxes				50

Year ended Dec. 31, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**2,259**	**3**	**-**	**2,262**
Fuel and purchased power	**809**	**-**	**-**	**809**
Gross margin	**1,450**	**3**	**-**	**1,453**
Operations, maintenance, and administration	**384**	**28**	**81**	**493**
Depreciation and amortization	**489**	**-**	**20**	**509**
Asset impairment charges	**324**	**-**	**-**	**324**
Inventory writedown	**44**	**-**	**-**	**44**
Restructuring charges	**5**	**-**	**8**	**13**
Taxes, other than income taxes	**27**	**-**	**1**	**28**
Intersegment cost allocation	**13**	**(13)**	**-**	**-**
Operating income (loss)	**164**	**(12)**	**(110)**	**42**
Finance lease income	**16**	**-**	**-**	**16**
Equity loss	**(15)**	**-**	**-**	**(15)**
Sundance Units 1 and 2 arbitration	**(254)**	**-**	**-**	**(254)**
Gain on sale of assets	**3**	**-**	**-**	**3**
Gain on sale of collateral	**-**	**15**	**-**	**15**
Other income				**1**
Foreign exchange loss				**(9)**
Net interest expense				**(242)**
Loss before income taxes				**(443)**

Year ended Dec. 31, 2011	Generation	Energy Trading	Corporate	Total
Revenues	2,526	137	-	2,663
Fuel and purchased power	947	-	-	947
Gross margin	1,579	137	-	1,716
Operations, maintenance, and administration	419	43	83	545
Depreciation and amortization	460	1	21	482
Asset impairment charges	17	-	-	17
Taxes, other than income taxes	27	-	-	27
Intersegment cost allocation	8	(8)	-	-
Operating income (loss)	648	101	(104)	645
Finance lease income	8	-	-	8
Equity income	14	-	-	14
Gain on sale of assets	16	-	-	16
Reserve on collateral	-	(18)	-	(18)
Other income				2
Foreign exchange loss				(3)
Net interest expense				(215)
Earnings before income taxes				449

GENERATION: *TransAlta 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. 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 2012 Annual MD&A.*

Generation Operations: *During 2012, we completed uprates at Keephills Units 1 and 2, which we expect will add an additional 26 MW of capacity at these plants. We also completed the uprate at Sundance Unit 3 which will add an expected 15 MW capacity at this facility. Although we completed the uprate at Sundance Unit 3, the resulting increased capacity will not be realized until we replace the generator stator. Please refer to the Significant Events section of our 2012 Annual MD&A for further discussion of these items. At Dec. 31, 2012, our generating assets had 8,200 MW of gross generating capacity[1] in operation (7,858 MW net ownership interest), 68 MW net under construction, and 560 MW under restoration in the Sundance Units 1 and 2 major project. The following information excludes assets that are accounted for as a finance lease or using the equity method, which are discussed separately within this discussion of the Generation Segment.*

The results of Generation Operations are as follows:

	2012				2011	
3 months ended Dec. 31	**Total**	**Comparable adjustments**	**Comparable total[2]**	**Per installed MWh**	Comparable total[2]	Per installed MWh
Revenues	**648**	**14**	**662**	**36.56**	659	36.52
Fuel and purchased power	**263**	**5**	**268**	**14.80**	292	16.18
Gross margin	**385**	**9**	**394**	**21.76**	367	20.34
Operations, maintenance, and administration	**92**	**-**	**92**	**5.08**	109	6.04
Depreciation and amortization	**114**	**-**	**114**	**6.30**	127	7.04
Inventory writedown	**10**	**-**	**10**	**0.55**	-	-
Restructuring charges	**5**	**(5)**	**-**	**-**	-	-
Taxes, other than income taxes	**5**	**-**	**5**	**0.28**	6	0.33
Intersegment cost allocation	**3**	**-**	**3**	**0.17**	2	0.11
Operating income	**156**	**14**	**170**	**9.38**	123	6.82
Installed capacity (GWh)	**18,106**		**18,106**		18,047	
Production (GWh)	**10,373**		**10,373**		11,158	
Availability (%)	**89.0**		**89.0**		90.2	

(1) We measure capacity as net maximum capacity (see glossary 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.

(2) Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this news release for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

	2012				2011	
Year ended Dec. 31	**Total**	**Comparable adjustments**	**Comparable total**	**Per installed MWh**	Comparable total	Per installed MWh
Revenues	**2,259**	**72**	**2,331**	**32.36**	2,399	33.94
Fuel and purchased power	**809**	**25**	**834**	**11.58**	947	13.40
Gross margin	**1,450**	**47**	**1,497**	**20.78**	1,452	20.54
Operations, maintenance and administration	**384**	**(3)**	**381**	**5.29**	413	5.84
Depreciation and amortization	**489**	**-**	**489**	**6.79**	456	6.45
Asset impairment charges	**324**	**(324)**	**-**	**-**	-	-
Inventory writedown	**44**	**(25)**	**19**	**0.26**	-	-
Restructuring charges	**5**	**(5)**	**-**	**-**	-	-
Taxes, other than income taxes	**27**	**-**	**27**	**0.37**	27	0.38
Intersegment cost allocation	**13**	**-**	**13**	**0.18**	8	0.11
Operating income	**164**	**404**	**568**	**7.89**	548	7.76
Installed capacity (GWh)	**72,028**		**72,028**		70,681	
Production (GWh)	**36,700**		**36,700**		38,911	
Availability (%)	**88.1**		**88.1**		84.8	

Generation Operations Production and Comparable Gross Margins

Production volumes, comparable revenues, fuel and purchased power expenses, and comparable gross margins based on geographical regions and fuel types are presented below.

3 months ended Dec. 31, 2012	**Production (GWh)**	**Installed (GWh)**	**Comparable revenues**	**Comparable fuel & purchased power**	**Comparable gross margin**	**Comparable revenues per installed MWh**	**Fuel & purchased power per installed MWh**	**Comparable gross margin per installed MWh**
Coal	**5,285**	**7,082**	**253**	**128**	**125**	**35.72**	**18.07**	**17.65**
Gas	**675**	**786**	**36**	**7**	**29**	**45.80**	**8.91**	**36.89**
Renewables	**716**	**2,953**	**64**	**2**	**62**	**21.67**	**0.68**	**20.99**
Total Western Canada	**6,676**	**10,821**	**353**	**137**	**216**	**32.62**	**12.66**	**19.96**
Gas	**838**	**1,656**	**99**	**45**	**54**	**59.78**	**27.17**	**32.61**
Renewables	**431**	**1,458**	**43**	**2**	**41**	**29.49**	**1.37**	**28.12**
Total Eastern Canada	**1,269**	**3,114**	**142**	**47**	**95**	**45.60**	**15.09**	**30.51**
Coal	**2,090**	**2,961**	**127**	**67**	**60**	**42.89**	**22.63**	**20.26**
Gas	**338**	**1,210**	**40**	**17**	**23**	**33.06**	**14.05**	**19.01**
Total International	**2,428**	**4,171**	**167**	**84**	**83**	**40.04**	**20.14**	**19.90**
	10,373	**18,106**	**662**	**268**	**394**	**36.56**	**14.80**	**21.76**

3 months ended Dec. 31, 2011	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	5,418	7,022	214	116	98	30.48	16.52	13.96
Gas	691	786	32	8	24	40.71	10.18	30.53
Renewables	815	2,953	65	3	62	22.01	1.02	20.99
Total Western Canada	6,924	10,761	311	127	184	28.90	11.80	17.10
Gas	855	1,656	102	47	55	61.59	28.38	33.21
Renewables	486	1,459	48	2	46	32.90	1.37	31.53
Total Eastern Canada	1,341	3,115	150	49	101	48.15	15.73	32.42
Coal	2,552	2,956	168	107	61	56.83	36.20	20.63
Gas	341	1,215	30	9	21	24.69	7.41	17.28
Total International	2,893	4,171	198	116	82	47.47	27.81	19.66
	11,158	18,047	659	292	367	36.52	16.18	20.34

Year ended Dec. 31, 2012	Production (GWh)	Installed (GWh)	Comparable revenues	Comparable fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	**20,265**	**28,168**	**985**	**439**	**546**	**34.97**	**15.59**	**19.38**
Gas	**2,558**	**3,128**	**116**	**22**	**94**	**37.08**	**7.03**	**30.05**
Renewables	**3,453**	**11,748**	**226**	**11**	**215**	**19.24**	**0.94**	**18.30**
Total Western Canada	**26,276**	**43,044**	**1,327**	**472**	**855**	**30.83**	**10.97**	**19.86**
Gas	**3,835**	**6,588**	**370**	**166**	**204**	**56.16**	**25.20**	**30.96**
Renewables	**1,486**	**5,802**	**145**	**7**	**138**	**24.99**	**1.21**	**23.78**
Total Eastern Canada	**5,321**	**12,390**	**515**	**173**	**342**	**41.57**	**13.96**	**27.61**
Coal	**3,736**	**11,780**	**367**	**150**	**217**	**31.15**	**12.73**	**18.42**
Gas	**1,367**	**4,814**	**122**	**39**	**83**	**25.34**	**8.10**	**17.24**
Total International	**5,103**	**16,594**	**489**	**189**	**300**	**29.47**	**11.39**	**18.08**
	36,700	**72,028**	**2,331**	**834**	**1,497**	**32.36**	**11.58**	**20.78**

Year ended Dec. 31, 2011	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	21,475	26,846	863	379	484	32.15	14.12	18.03
Gas	2,588	3,282	118	33	85	35.95	10.05	25.90
Renewables	3,237	11,645	220	11	209	18.89	0.94	17.95
Total Western Canada	27,300	41,773	1,201	423	778	28.75	10.13	18.62
Gas	3,578	6,570	410	219	191	62.40	33.33	29.07
Renewables	1,521	5,790	147	7	140	25.39	1.21	24.18
Total Eastern Canada	5,099	12,360	557	226	331	45.06	18.28	26.78
Coal	5,135	11,742	520	261	259	44.29	22.23	22.06
Gas	1,377	4,806	121	37	84	25.18	7.70	17.48
Total International	6,512	16,548	641	298	343	38.74	18.01	20.73
	38,911	70,681	2,399	947	1,452	33.94	13.40	20.54

Western Canada

Our Western Canada assets consist of coal, natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our Western Canadian operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31 (GWh)	**Year ended Dec. 31 (GWh)**
Production, 2011	6,924	27,300
Higher planned outages at the Alberta coal PPA facilities	(219)	(1,415)
Lower PPA customer demand	(187)	(1,200)
Market curtailments	74	(272)
Higher planned outages at Genesee Unit 3	(219)	(219)
Lower wind volumes	(93)	(112)
Commencement of commercial operations of Keephills Unit 3	-	1,063
Lower unplanned outages at the Alberta coal PPA facilities	75	482
(Lower) higher hydro volumes	(6)	327
Lower unplanned outages at Genesee Unit 3	278	164
Higher production due to facility uprates	68	93
(Lower) higher production at natural gas-fired facilities	(16)	58
Other	(3)	7
Production, 2012	**6,676**	**26,276**

The primary factors contributing to the change in comparable gross margin for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Comparable gross margin, 2011	184	778
Pricing, primarily related to penalties paid and recovered under Alberta coal PPAs	38	69
Commencement of commercial operations of Keephills Unit 3 and uprates	3	53
Higher hydro margins	11	51
Lower unplanned outages at the Alberta coal PPA facilities	6	42
Lower unplanned outages at Genesee Unit 3	15	9
Higher planned outages at the Alberta coal PPA facilities	(19)	(74)
Unfavourable coal pricing	(15)	(38)
Higher planned outages at Genesee Unit 3	(12)	(12)
Market curtailments	3	(12)
Lower wind volumes	(5)	(7)
Other	7	(4)
Comparable gross margin, 2012	**216**	**855**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our Eastern Canadian operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2011	1,341	5,099
(Unfavourable) favourable market conditions at natural gas-fired facilities	(17)	257
Lower wind volumes	(54)	(19)
Other	(1)	(16)
Production, 2012	**1,269**	**5,321**

The primary factors contributing to the change in gross margin for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Gross margin, 2011	101	331
Favourable contracted gas input costs	-	14
Lower wind volumes	(5)	(3)
Other	(1)	-
Gross margin, 2012	**95**	**342**

International

Our International assets consist of coal, natural gas, and hydro facilities in various locations in the United States, and natural gas and diesel assets in Australia. Refer to the Discussion of Segmented Results section of our 2012 Annual MD&A for further details on our International operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2011	2,893	6,512
Higher economic dispatching at Centralia Thermal	(358)	(3,764)
(Higher) lower planned and unplanned outages at Centralia Thermal	(101)	2,372
Other	(6)	(17)
Production, 2012	**2,428**	**5,103**

The primary factors contributing to the change in comparable gross margin for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Comparable gross margin, 2011	82	343
Favourable (unfavourable) pricing, including margins on purchased power	2	(41)
Unfavourable foreign exchange	(2)	(1)
Other	1	(1)
Comparable gross margin, 2012	**83**	**300**

The outages at Centralia Thermal did not negatively impact our gross margins for the three months and years ended Dec. 31, 2012 and 2011 as we were able to extend some of our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Overall fleet availability, after adjusting for the extended planned outages at Centralia, was 90.0 per cent for the year ended Dec. 31, 2012 (Dec. 31, 2011 - 88.2 per cent).

Operations, Maintenance, and Administration Expense

OM&A expenses for the three months and year ended Dec. 31, 2012 decreased compared to the same periods in 2011, primarily due to lower compensation costs as a result of productivity initiatives and a continued focus on costs.

Depreciation and Amortization Expense

The primary factors contributing to the change in depreciation and amortization expense for the three months and year ended Dec. 31, 2012 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Depreciation and amortization expense, 2011	127	460
Increase in asset base	5	37
Asset retirements	(1)	17
Impact of asset impairments	(9)	(17)
Change in economic life[1]	(6)	(12)
Other	(2)	4
Depreciation and amortization expense, 2012	**114**	**489**

Asset Impairment Charges

Centralia Thermal

In 2011, the Bill was signed into law in the State of Washington. The Bill, and the Memorandum of Agreement (the "MoA") signed on Dec. 23, 2011, provides a framework to transition from coal-fired energy produced at our Centralia Thermal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of the shut down of the units and the removal of restrictions on the terms of power contracts that we can enter into.

On July 25, 2012, we announced that a long-term power agreement was signed for the supply of power from December 2014 until the Centralia Thermal plant is fully retired in 2025. Refer to the Subsequent Events section of this news release for further discussion. As a result, we completed an assessment of whether the carrying amount of the facility was recoverable based on an estimate of fair value less costs to sell. The fair value was determined based on the future cash flows expected to be derived from the plant's operations, determined by prices evidenced in the agreement and in the marketplace. A pre-tax impairment charge of $347 million resulted and is included in the Generation Segment.

In addition to the impairment charge, $169 million of deferred income tax assets were written off as it is no longer probable that sufficient taxable income will be available from our U.S. operations to allow the benefit associated with the deferred income tax assets to be utilized.

The cumulative $516 million impact associated with the plant impairment and writeoff of deferred income tax assets has been adjusted in calculating earnings on a comparable basis. Please refer to the Non-IFRS Measures section of this news release.

Sundance Units 1 and 2

During 2012, we recognized a net pre-tax impairment charge of $2 million, comprised of a $43 million charge in the second quarter that resulted from the conclusion of the Sundance Units 1 and 2 arbitration and a $41 million reversal in the third quarter that arose as a result of the additional years of merchant operations expected to be realized at Sundance Units 1 and 2 due to recent amendments to Canadian federal regulations. The impairment losses and reversal are included in the Generation Segment.

(1) As a result of amendments to Canadian federal regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation. The previous draft regulations proposed shut down after 45 years.

Renewables

During 2012, we recognized a pre-tax impairment charge of $18 million related to five assets within the renewables fleet. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs to sell, derived from the long-range forecasts and prices evidenced in the marketplace. The assets were impaired primarily due to expectations regarding lower market prices. The impairment losses are included in the Generation Segment.

Reversals

As evidenced by the Sundance Units 1 and 2 impairment reversal discussed above, the impairment charges can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants improve. The reduction of the deferred income tax asset can also be reversed if the estimated taxable income to be generated by our U.S. operations, which include the Centralia Thermal plant, improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Finance Leases

Solomon

On Sept. 28, 2012, we announced that we completed the acquisition from Fortescue Metals Group Ltd. (“Fortescue”) of its 125 MW natural gas-fired and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility and associated Power Purchase Agreement (“Agreement”) are accounted for as a finance lease. The facility is currently under construction and is expected to be commissioned during the first half of 2013.

Fort Saskatchewan

Fort Saskatchewan is a natural gas-fired facility with a gross generating capacity of 118 MW in operation, of which TransAlta Cogeneration, L.P. has a 60 per cent ownership interest (35 MW net ownership interest). Key operational information adjusted to reflect our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

	3 months ended Dec. 31		**Year ended Dec. 31**	
	2012	2011	**2012**	2011
Availability (%)	**103.7**	100.4	**92.0**	98.1
Production (GWh)	**138**	130	**470**	481

Availability for the three months ended Dec. 31, 2012 increased compared to the same period in 2011, due to lower planned and unplanned outages.

For the year ended Dec. 31, 2012, availability decreased compared to 2011, primarily due to higher planned outages.

Production for the three months ended Dec. 31, 2012 increased by 8 GWh compared to the same period in 2011, due to lower planned and unplanned outages and increased customer demand.

For the year ended Dec. 31, 2012, production decreased by 11 GWh compared to 2011, due to higher planned outages, partially offset by increased customer demand.

Total Finance Lease Income

Total finance lease income for the three months and year ended Dec. 31, 2012 increased $9 million and $8 million, respectively, compared to the same periods in 2011 due to the payments we began receiving in October 2012 under the Agreement with Fortescue.

Please refer to *Note 9* of our audited consolidated financial statements within our 2012 Annual Report for additional information regarding the Fort Saskatchewan and Solomon finance leases.

Equity Investments

Our interests in the CE Gen and Wailuku River Hydroelectric, L.P. joint ventures are accounted for using the equity method and are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 839 MW of gross generating capacity (390 MW net ownership interest). The table below summarizes key operational information adjusted to reflect our interest in these investments:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Availability (%)	**93.8**	90.5	**94.2**	94.9
Production (GWh)				
Gas	**90**	24	**380**	308
Renewables	**279**	350	**1,200**	1,312
Total production	**369**	374	**1,580**	1,620

Availability for the three months ended Dec. 31, 2012 increased compared to the same period in 2011 due to lower planned outages.

Availability for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 due to higher unplanned outages.

Production for the three months ended Dec. 31, 2012 decreased compared to 2011 due to lower customer demand, partially offset by lower planned outages.

For the year ended Dec. 31, 2012, production decreased compared to the same period in 2011 due to higher unplanned outages and lower customer demand.

Equity income for the three months ended Dec. 31, 2012 decreased $8 million compared to the same period in 2011 primarily due to unfavourable pricing.

For the year ended Dec. 31, 2012, equity income decreased $29 million compared to 2011 due to higher unplanned outages and unfavourable pricing.

Since 2001, a significant portion of the CE Gen plants have been operating under modified fixed energy price contracts. Commencing May 1, 2012, the terms of the contracts reverted to a pricing clause that permits the power purchaser to pay their short-run avoided costs ("SRAC") as the price for power. The SRAC is linked to the price of natural gas. There can be no assurances that prices based on the avoided cost of energy after May 1, 2012 will result in revenues equivalent to those realized under the fixed energy price structure.

Please refer to *Note 10* of our audited consolidated financial statements within our 2012 Annual Report for additional financial information regarding our investments accounted for using the equity method.

ENERGY TRADING: *Derives revenue and earnings from the wholesale 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 2012 Annual MD&A for further discussion on VaR.*

Energy Trading utilizes contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. If the activities are performed on behalf of the Generation Segment, the results of these activities are included in the Generation Segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2012 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 Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Revenues	**13**	40	**3**	137
Fuel and purchased power	**-**	-	**-**	-
Gross margin	**13**	40	**3**	137
Operations, maintenance, and administration	**8**	16	**28**	43
Depreciation and amortization	**-**	-	**-**	1
Intersegment cost allocation	**(3)**	(2)	**(13)**	(8)
Operating income (loss)	**8**	26	**(12)**	101

For the three months and year ended Dec. 31, 2012, Energy Trading gross margins decreased compared to the same periods in 2011 primarily due to the impact of unexpected weather patterns, plant outages, and unfavourable market expectations on power and gas pricing for trading positions held.

OM&A expenses for the three months and year ended Dec. 31, 2012 decreased compared to the same periods in 2011 primarily due to decreased compensation costs as a result of lower earnings.

For the three months and year ended Dec. 31, 2012, the intersegment cost allocation increased compared to the same periods in 2011 due to additional support costs charged to the Generation Segment resulting from an increase in work performed by Energy Trading.

CORPORATE: *Our Generation and Energy Trading Segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, 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 Dec. 31				Year ended Dec. 31			
	2012	**Comparable adjustments**	**Comparable total**	2011	**2012**	**Comparable adjustments**	**Comparable total**	2011
Operations, maintenance, and administration	**18**	**-**	**18**	19	**81**	**-**	**81**	83
Depreciation and amortization	**5**	**-**	**5**	6	**20**	**-**	**20**	21
Restructuring charges	**8**	**(8)**	**-**	-	**8**	**(8)**	**-**	-
Taxes, other than income taxes	**1**	**-**	**1**	-	**1**	**-**	**1**	-
Operating loss	**32**	**(8)**	**24**	25	**110**	**(8)**	**102**	104

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Interest on debt	**60**	60	**227**	228
Interest income	**(1)**	-	**(2)**	-
Capitalized interest	**(2)**	-	**(4)**	(31)
Ineffectiveness on hedges	**1**	-	**4**	(1)
Other	**(1)**	-	**-**	-
Interest expense	**57**	60	**225**	196
Accretion of provisions	**3**	4	**17**	19
Net interest expense	**60**	64	**242**	215

The change in net interest expense for the three months and year ended Dec. 31, 2012, compared to the same periods in 2011, is shown below:

	3 months ended Dec. 31	**Year ended Dec. 31**
Net interest expense, 2011	64	215
(Higher) lower capitalized interest	(2)	27
(Lower) higher interest rates	(2)	1
Favourable foreign exchange impacts	(1)	-
Higher ineffectiveness on hedges	1	5
Higher financing costs	1	-
Higher interest income	(1)	(2)
Lower accretion	(1)	(2)
Higher (lower) debt levels	1	(2)
Net interest expense, 2012	**60**	**242**

INCOME TAXES

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Earnings (loss) before income taxes	**71**	50	**(443)**	449
Income attributable to non-controlling interests	**(12)**	(11)	**(37)**	(38)
Equity (income) loss	**10**	2	**15**	(14)
Impacts associated with certain de-designated and ineffective hedges	**14**	(2)	**72**	(127)
Asset impairment charges	**-**	3	**324**	17
Inventory writedown	**(5)**	-	**-**	**-**
Restructuring charges	**13**	-	**13**	**-**
Gain on sale of assets	**-**	(13)	**(3)**	(16)
Sundance Units 1 and 2 arbitration	**-**	-	**254**	-
Reserve on (gain on sale of) collateral	**-**	18	**(15)**	18
Other non-comparable items	**-**	1	**3**	10
Earnings attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**91**	48	**183**	299
Income tax expense	**11**	11	**103**	106
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**5**	(1)	**25**	(46)
Income tax (expense) recovery related to asset impairment charges	**-**	1	**(5)**	4
Income tax expense related to inventory writedown	**(2)**	**-**	**-**	**-**
Income tax recovery related to restructuring charges	**3**	-	**3**	-
Income tax expense related to gain on sale of assets	**-**	(3)	**(1)**	(4)
Income tax recovery related to Sundance Units 1 and 2 arbitration	**-**	-	**65**	-
Income tax recovery (expense) related to reserve on (gain on sale of) collateral	**-**	5	**(4)**	5
Income tax expense related to writeoff of deferred income tax assets	**-**	-	**(169)**	-
Income tax expense related to changes in corporate income tax rates	**-**	-	**(8)**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**9**	-
Reclassification of Part VI.1 tax	**-**	(2)	**-**	(2)
Income tax recovery related to other non-comparable items	**-**	-	**1**	3
Income tax expense excluding non-comparable items	**17**	11	**19**	66
Effective tax rate on earnings (loss) attributable to TransAlta shareholders excluding non-comparable items (%)	**19**	23	**10**	22

The income tax expense excluding non-comparable items for the three months ended Dec. 31, 2012 increased compared to the same period in 2011 due to higher comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The income tax expense excluding non-comparable items for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 due to lower comparable earnings, changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, and the positive resolution of certain outstanding tax matters.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three months ended Dec. 31, 2012 decreased compared to the same period in 2011 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.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the year ended Dec. 31, 2012 decreased compared to the same period in 2011 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, the effect of certain deductions that do not fluctuate with earnings, and the positive resolution of certain outstanding tax matters.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three months and year ended Dec. 31, 2012 was comparable to the same periods in 2011.

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the three months and year ended Dec. 31, 2012 compared to the same periods in 2011:

3 months ended Dec. 31	**2012**	2011	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**71**	66	
Provided by (used in):			
Operating activities	**245**	187	Favourable changes in working capital of $42 million and higher cash earnings of $16 million
Investing activities	**(226)**	(208)	Increase in additions to PP&E and intangibles of $81 million and lower proceeds on sale of PP&E and facilities of $16 million, partially offset by a net positive cash impact of $57 million related to changes in collateral received from or paid to counterparties and a favourable change in non-cash investing working capital balances of $21 million
Financing activities	**(64)**	3	Decrease in proceeds from issuance of preferred shares of $267 million, increased borrowings under credit facilities of $162 million, and an increase in realized losses on financial instruments of $45 million, offset by an issuance of $388 million in long-term debt
Translation of foreign currency cash	**1**	1	
Cash and cash equivalents, end of period	**27**	49	

Year ended Dec. 31	2012	2011	Primary factors explaining change
Cash and cash equivalents, beginning of period	**49**	35	
Provided by (used in):			
Operating activities	**520**	690	Lower cash earnings of $33 million and unfavourable changes in working capital of $137 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration
Investing activities	**(1,048)**	(608)	Acquisition of Solomon finance lease for $312 million, an increase in additions to PP&E and intangibles of $259 million and a decrease in proceeds on sale of PP&E and facilities of $46 million, partially offset by a net positive impact of $176 million related to changes in collateral received from or paid to counterparties
Financing activities	**504**	(70)	Issuance of long-term debt of $388 million, increase in issuance of common shares of $291 million, and a decrease in common share cash dividends of $87 million due to dividends reinvested through the dividend reinvestment plan, partially offset by an increase in debt repayments of $80 million, a decrease of $50 million in proceeds from the issuance of preferred shares, an increase in realized losses on financial instruments of $40 million, and an increase in preferred share dividends of $17 million
Translation of foreign currency cash	**2**	2	
Cash and cash equivalents, end of period	**27**	49	

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

On Feb. 26, 2013, we had 258.4 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E first preferred shares outstanding. At Dec. 31, 2012, we had 254.7 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. At Dec. 31, 2012, we also had 12.0 million (Dec. 31, 2011 - 12.0 million) Series A, 11.0 million (Dec. 31, 2011 - 11.0 million) Series C, and 9.0 million Series E (Dec. 31, 2011 - nil) first preferred shares issued and outstanding.

We issue common shares for cash proceeds, on exercise of stock options and other share-based payment plans, or for reinvestment of dividends. During February 2012, we added a Premium Dividend™ component to the Plan. Please refer to *Note 28* of our audited consolidated financial statements within our 2012 Annual Report for additional information regarding the amendments.

During the three months ended Dec. 31, 2012, 3.5 million (Dec. 31, 2011 - 0.7 million) common shares were issued for $49 million (Dec. 31, 2011 - $18 million), which was comprised of 3.5 million (Dec. 31, 2011 - 0.7 million) common shares for $49 million (Dec. 31, 2011 - $18 million) for dividends reinvested under the terms of the Plan. During the year ended Dec. 31, 2012, 31.1 million (Dec. 31, 2011 - 3.3 million) common shares were issued for $456 million (Dec. 31, 2011 - $69 million), which was comprised of 21.2 million (Dec. 31, 2011 - nil) common shares issued through a public offering for total net proceeds of $295 million (Dec. 31, 2011 - nil), 9.7 million (Dec. 31, 2011 - 3.2 million) common shares for $159 million (Dec. 31, 2011 - $67 million) for dividends reinvested under the terms of the Plan and 0.2 million (Dec. 31, 2011 - 0.1 million) common shares were issued for proceeds of $2 million (Dec. 31, 2011 - $2 million).

We employ a variety of share-based payment plans to align employee and corporate objectives. During the year ended Dec. 31, 2012, 0.1 million employee stock options were exercised, expired or were cancelled (Dec. 31, 2011 - 0.1 million). No employee stock options were granted during the years ended Dec. 31, 2012 and 2011. During the year ended Dec. 31, 2012, 1.5 million (Dec. 31, 2011 - 1.4 million) Performance Share Ownership Plan units were granted and 0.1 million (Dec. 31, 2011 - a nominal amount) were awarded and exchanged for common shares.

2013 OUTLOOK

Business Environment

Power Prices

In 2013, power prices in Alberta are expected to be lower than in 2012 due to fewer planned turnarounds and increased capacity due to additional generation facilities coming online, partially offset by load growth. In the Pacific Northwest, we expect prices to be modestly stronger than in 2012; however, overall prices will still remain weak because of low natural gas prices and slow load growth.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. We are in discussions with the provincial government 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 the regulatory requirements. For further information on the Canadian GHG regulations, please refer to the Significant Events section of our 2012 Annual MD&A.

In addition, there are ongoing discussions between the federal and provincial governments regarding a national Air Quality Management System for air pollutants. In Alberta's recently released Clean Air Strategy, the province indicated that its provincial air quality management system will operationalize any national system. Our current outlook is that, for Alberta, provincial regulations will be considered as equivalent to any future national framework.

In the U.S., it is not yet clear how climate change legislation for existing fossil-fuel-based generation will unfold. Additionally, new air pollutant regulations for the power sector are anticipated, but will not directly affect our coal-fired operations in Washington State. TransAlta's agreement with Washington State, established in April 2011, provides regulatory clarity at the state level regarding an emissions regime related to the Centralia Coal plant until 2025.

Beginning in 2013, direct deliveries of power to the California Independent System Operator will be subject to a compliance obligation established by the California Air Resources Board's ("CARB") cap and trade program. As CARB continues to finalize their regulations, we will stay at the forefront of regulatory changes to ensure we remain in compliance with the cap and trade program.

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

The siting, construction, and operation of electrical energy facilities requires interaction with many stakeholders. Recently, certain stakeholders have brought actions against government agencies and owners over alleged adverse impacts of wind projects. We are monitoring these claims in order to assess the risk associated with these activities.

Economic Environment

The economic environment showed signs of weakness during 2012 and in 2013 we expect slow to moderate growth in Alberta and Australia, and low growth in other 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 2012, and we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. 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 in 2013 due to Sundance Units 1 and 2 returning to service and the completion of the New Richmond facility. Prior to the effect of any economic dispatching, overall production is expected to increase in 2013 due to lower planned outages. Overall availability is expected to be in the range of 89 to 90 per cent in 2013 due to lower planned outages across the fleet.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 77 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 year. As at the end of 2012, approximately 85 per cent of our 2013 capacity was contracted. The average price of our short-term physical and financial contracts for 2013 ranges from $60 to $65 per megawatt hour ("MWh") in Alberta, and from U.S.$40 to $45 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. In January 2013, we gave notice to Prairie Mines and Royalty Ltd. that we will assume, through our wholly owned SunHills Mining Limited Partnership, operating and management control of the Highvale Mine. We are currently assessing the accounting impact of this change. Coal costs for 2013, on a standard cost basis, are expected to be comparable to 2012 with the assumption of operational and management control offsetting any cost increases mentioned above.

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 2013 is expected to decrease by a range of nine to eleven 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 will be recognized in net earnings. For more information on the inventory impairment charges and reversals recorded in 2012, please refer to the Significant Events section of our 2012 Annual MD&A.

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.

Operations, Maintenance, and Administration Costs

OM&A costs for 2013 are expected to be relatively consistent with 2012 OM&A, primarily due to cost savings as a result of our restructuring in the fourth quarter offset by additional costs as Sundance Units 1 and 2 are returned to service and the commencement of operations at our New Richmond facility.

Energy Trading

Earnings from our Energy Trading Segment are affected by prices 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 target is for Energy Trading to contribute between $40 million and $60 million in gross margin for 2013.

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 net foreign denominated revenues.

Net Interest Expense

Net interest expense for 2013 is not expected to change materially compared to 2012. 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 2012 Annual MD&A, are based on the current economic environment and outlook. As a result of 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 2013 is expected to be approximately 22 to 27 per cent, which is comparable to the statutory tax rate of 25 per cent.

Capital Expenditures

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

Growth and Major Project Expenditures

We have one significant growth capital project that is currently in progress with targeted completion date of Q1 2013 and one additional major project with a targeted completion date of Q4 2013. A summary of each of these items is outlined below:

	Total Project		**2012**[(1)]	**2013**	**Target**	
	Estimated spend	**Spent to date**[(2)]	**Actual spend**	**Estimated spend**	**completion date**	**Details**
Growth						
New Richmond[(3)]	212	188	159	15 - 25	Q1 2013	A 68 MW wind farm in Quebec
Major projects						
Sundance Units 1 and 2	190	44	44	130 - 145	Q4 2013	Sundance Units 1 and 2 comprising 560 MW of our Sundance power plant
Total major projects and growth	**402**	**232**	**203**	**145 - 170**		

Our total estimated spend for New Richmond increased by $7 million primarily due to unfavourable foreign exchange rates and increased costs incurred due to construction delays.

During 2012, we entered into an agreement with Alstom Power & Transport Canada Inc. for the manufacture, delivery, and construction of the Sundance Units 1 and 2 waterwalls. The total fixed price commitment under the contract is $79 million, with $25 million incurred in 2012 and $54 million expected to be incurred in 2013. Payments will be made as agreed milestones are achieved. Additional costs to be paid under the contract include reimbursable items, such as direct labour, subcontractors, and labour incentive allowances.

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(1) In 2012, we also spent a combined $40 million on facilities that had previously commenced operations. During the second quarter of 2012, we transferred $1 million from growth and major projects to sustaining capital and productivity expenditures for capital spares.

(2) Represents amounts spent as of Dec. 31, 2012.

(3) New Richmond total project costs spent to date include expenditures of $5 million that were included in project development costs in 2011.

Transmission

For the three months and year ended Dec. 31, 2012, a total of $1 million and $4 million, respectively, was spent on transmission projects. The estimated spend for 2013 on transmission projects is $7 million. Transmission projects consist of the major maintenance and reconfiguration of Alberta's transmission networks to increase capacity of power flow in the lines.

Sustaining Capital and Productivity Expenditures

For 2013, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Spent in 2012	Expected spend in 2013
Routine capital	Expenditures to maintain our existing generating capacity	115	90 - 100
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	38	40 - 50
Planned major maintenance	Regularly scheduled major maintenance	286	165 - 185
Total sustaining expenditures		**439**	**295 - 335**
Productivity capital	Projects to improve power production efficiency	57	30 - 50
Total sustaining and productivity expenditures		**496**	**325 - 385**

As a result of assuming the operating and management control of the Highvale Mine, sustaining capital and productivity expenditures for 2013 may be adjusted throughout the year as additional costs are incurred. We are currently assessing the impact that this will have on our 2013 sustaining capital and productivity expenditures.

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 2013 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2013
Capitalized	90 - 105	75 - 80	165 - 185
Expensed	-	0 - 5	0 - 5
	90 - 105	75 - 85	165 - 190

	Coal	Gas and Renewables	Total
GWh lost	1,660 - 1,670	420 - 430	2,080 - 2,100

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, reinvested dividends 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.

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 Consolidated Statements of Earnings (Loss) for the three months and year ended Dec. 31, 2012 and 2011. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

NON-IFRS MEASURES

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

Presenting earnings on a comparable basis, comparable gross margin, comparable operating income, and 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. 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. In calculating comparable earnings measures we have also excluded, as applicable, the inventory writedown, as the recognition of the writedown is related to the hedges that were de-designated or deemed ineffective during prior quarters.

We have also excluded the impact of the asset impairment charges related to Centralia Thermal, which was determined based on the future cash flows expected to be derived from the plant's operations, the related writeoff of deferred income tax assets, the impacts of the Sundance Units 1 and 2 arbitration, and impairment charges recorded on assets in the renewables fleet.

Other one-time adjustments to earnings, such as the income tax expense related to changes in corporate income tax rates, the impact to revenue associated with Sundance Units 1 and 2, the income tax recovery related to the resolution of certain outstanding tax matters, the gain on sale of assets, the writeoff of Project Pioneer costs, the gain on sale of (reserve on) collateral, restructuring charges, the writeoff of wind development costs, and the writedown of certain capital spares, 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.

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.

Reconciliation to Net Earnings Attributable to Common Shareholders

Gross margin and operating income are reconciled to net earnings attributable to common shareholders below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Revenues	**661**	701	**2,262**	2,663
Fuel and purchased power	**263**	292	**809**	947
Gross margin	**398**	409	**1,453**	1,716
Operations, maintenance, and administration	**118**	145	**493**	545
Depreciation and amortization	**119**	133	**509**	482
Asset impairment charges	**-**	3	**324**	17
Inventory writedown	**10**	-	**44**	-
Restructuring charges	**13**	-	**13**	-
Taxes, other than income taxes	**6**	6	**28**	27
Operating income	**132**	122	**42**	645
Finance lease income	**11**	2	**16**	8
Equity income (loss)	**(10)**	(2)	**(15)**	14
Sundance Units 1 and 2 arbitration	**-**	**-**	**(254)**	**-**
Gain on sale of assets	**-**	13	**3**	16
Other income	**-**	-	**1**	2
Foreign exchange loss	**(2)**	(3)	**(9)**	(3)
Gain on sale of (reserve on) collateral	**-**	(18)	**15**	(18)
Net interest expense	**(60)**	(64)	**(242)**	(215)
Earnings (loss) before income taxes	**71**	50	**(443)**	449
Income tax expense	**11**	11	**103**	106
Net earnings (loss)	**60**	39	**(546)**	343
Non-controlling interests	**12**	11	**37**	38
Net earnings (loss) attributable to TransAlta shareholders	**48**	28	**(583)**	305
Preferred share dividends	**10**	4	**31**	15
Net earnings (loss) attributable to common shareholders	**38**	24	**(614)**	290

Net Earnings on a Comparable Basis

Net earnings on a comparable basis are reconciled to net earnings (loss) attributable to common shareholders below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Net earnings (loss) attributable to common shareholders	**38**	24	**(614)**	290
Impacts associated with certain de-designated and ineffective hedges, net of tax	**9**	(1)	**47**	(81)
Asset impairment charges, net of tax	**-**	2	**329**	13
Inventory writedown, net of tax	**(3)**	-	**-**	-
Restructuring charges, net of tax	**10**	-	**10**	-
Sundance Units 1 and 2 arbitration, net of tax	**-**	-	**189**	-
Income tax expense related to writeoff of deferred income tax assets	**-**	-	**169**	-
Income tax expense related to changes in corporate income tax rates	**-**	-	**8**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**(9)**	-
Gain on sale of assets, net of tax	**-**	(10)	**(2)**	(12)
Writeoff of Project Pioneer costs, net of tax	**-**	-	**2**	-
Reserve on (gain on sale of) collateral, net of tax	**-**	13	**(11)**	13
Writeoff of wind development costs, net of tax	**-**	1	**-**	4
Writedown of capital spares, net of tax	**-**	-	**-**	3
Net earnings on a comparable basis	**54**	29	**118**	230
Weighted average number of common shares outstanding in the period	**255**	224	**235**	222
Net earnings on a comparable basis per share	**0.21**	0.13	**0.50**	1.04

Comparable Gross Margin

Comparable gross margin is calculated as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Gross margin	**398**	409	**1,453**	1,716
Impacts associated with certain de-designated and ineffective hedges	**14**	(2)	**72**	(127)
Impacts to revenue associated with Sundance Units 1 and 2(1)	**-**	(8)	**(20)**	(40)
Inventory writedown	**(5)**	-	**(25)**	-
Comparable gross margin	**407**	399	**1,480**	1,549

(1) The results have been adjusted retroactively for the impact of Sundance Units 1 and 2. Comparative figures have also been adjusted in this table only to provide period over period comparability.

Comparable Operating Income

A reconciliation of comparable operating income is as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Operating income	**132**	122	**42**	645
Impacts associated with certain de-designated and ineffective hedges	**14**	(2)	**72**	(127)
Asset impairment charges	**-**	3	**324**	17
Inventory writedown	**(5)**	-	**-**	-
Restructuring charges	**13**	-	**13**	-
Finance lease income	**11**	2	**16**	8
Writeoff of Project Pioneer costs	**-**	-	**3**	-
Writeoff of wind development costs	**-**	1	**-**	6
Writedown of capital spares	**-**	-	**-**	4
Comparable operating income	**165**	126	**470**	553

Comparable EBITDA

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.

A reconciliation of comparable EBITDA to operating income is as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2012	2011	**2012**	2011
Operating income	**132**	122	**42**	645
Asset impairment charges	**-**	3	**324**	17
Inventory writedown	**(5)**	-	**-**	-
Restructuring charges	**13**	-	**13**	-
Finance lease income	**11**	2	**16**	8
Depreciation and amortization per the Consolidated Statements of Cash Flows[(1)]	**145**	149	**564**	532
Impacts associated with certain de-designated and ineffective hedges	**14**	(2)	**72**	(127)
Impacts to revenue associated with Sundance Units 1 and 2	**-**	(8)	**(20)**	(40)
Writeoff of Project Pioneer costs	**-**	-	**3**	-
Writeoff of wind development costs	**-**	1	**-**	6
Writedown of capital spares	**-**	-	**-**	4
Comparable EBITDA	**310**	267	**1,014**	1,045

(1) To calculate comparable EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in fuel and purchased power on the Consolidated Statements of Earnings.

Funds from Operations and Funds from Operations per Share

Presenting funds from operations and funds from operations 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. Funds from operations per share is calculated as follows using the weighted average number of common shares outstanding during the period:

	3 months ended Dec. 31		**Year ended Dec. 31**	
	2012	2011	**2012**	2011
Cash flow from operating activites	**245**	187	**520**	690
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	**204**	-
Change in non-cash operating working capital balances	**(40)**	2	**52**	119
Funds from operations	**205**	189	**776**	809
Weighted average number of common shares outstanding in the period	**255**	224	**235**	222
Funds from operations per share	**0.80**	0.84	**3.30**	3.64

Free Cash Flow

Free cash flow represents the amount of cash generated from operations by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments of debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash flow with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects.

Sustaining capital and productivity expenditures for the three months ended Dec. 31, 2012 represent total additions to property, plant, and equipment and intangibles per the Consolidated Statements of Cash Flows less $102 million that we have invested in projects and growth. For the same period in 2011, we invested $38 million ($37 million net of joint venture contributions) in projects and growth. For the year ended Dec. 31, 2012 and 2011, we invested $246 million and $126 million ($124 million net of joint venture contributions), respectively, in projects and growth.

The reconciliation between cash flow from operating activities and free cash flow is outlined below:

	3 months ended Dec. 31		**Year ended Dec. 31**	
	2012	2011	**2012**	2011
Cash flow from operating activities	**245**	187	**520**	690
Add (deduct):				
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	**204**	-
Changes in non-cash operating working capital	**(40)**	2	**52**	119
Sustaining capital and productivity expenditures	**(128)**	(111)	**(496)**	(357)
Dividends paid on common shares[1]	**(18)**	(48)	**(104)**	(191)
Dividends paid on preferred shares	**(11)**	(4)	**(32)**	(15)
Distributions paid to subsidiaries' non-controlling interests	**(17)**	(17)	**(59)**	(61)
Free cash flow	**31**	9	**85**	185

(1) Net of dividends reinvested under the Plan.

We seek to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to our business.

SELECTED QUARTERLY INFORMATION

	Q1 2012	Q2 2012	Q3 2012	**Q4 2012**
Revenue	656	407	538	**661**
Net earnings (loss) attributable to common shareholders	89	(797)	56	**38**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.40	(3.51)	0.24	**0.15**
Comparable earnings (loss) per share	0.20	(0.10)	0.18	**0.21**

	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Revenue	818	515	629	701
Net earnings attributable to common shareholders	204	12	50	24
Net earnings per share attributable to common shareholders, basic and diluted	0.92	0.05	0.22	0.11
Comparable earnings per share	0.34	0.29	0.27	0.13

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.

FORWARD-LOOKING STATEMENTS

This news release, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "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 news release contains forward-looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and major projects, and their attendant costs; our estimated spend 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; expected impacts of load growth and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; expectations for the outcome of existing or potential legal and contractual claims; 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; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment; our credit practices; and the estimated contribution of Energy Trading activities to gross margin.

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 disasters; the threat of domestic terrorism and cyber-attacks; equipment failure; 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 and contractual proceedings involving the Corporation; reliance on key personnel; labour relations matters; and development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2012 Annual MD&A and under the heading “Risk Factors” in our 2013 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.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(in millions of Canadian dollars except per share amounts)

Unaudited	3 months ended Dec. 31 **2012**	2011	Year ended Dec. 31 **2012**	2011
Revenues	**661**	701	**2,262**	2,663
Fuel and purchased power	**263**	292	**809**	947
Gross margin	**398**	409	**1,453**	1,716
Operations, maintenance, and administration	**118**	145	**493**	545
Depreciation and amortization	**119**	133	**509**	482
Asset impairment charges	**-**	3	**324**	17
Inventory writedown	**10**	-	**44**	-
Restructuring charges	**13**	-	**13**	-
Taxes, other than income taxes	**6**	6	**28**	27
Operating income	**132**	122	**42**	645
Finance lease income	**11**	2	**16**	8
Equity income (loss)	**(10)**	(2)	**(15)**	14
Sundance Units 1 and 2 arbitration	**-**	-	**(254)**	-
Gain on sale of assets	**-**	13	**3**	16
Other income	**-**	-	**1**	2
Foreign exchange loss	**(2)**	(3)	**(9)**	(3)
Gain on sale of (reserve on) collateral	**-**	(18)	**15**	(18)
Net interest expense	**(60)**	(64)	**(242)**	(215)
Earnings (loss) before income taxes	**71**	50	**(443)**	449
Income tax expense	**11**	11	**103**	106
Net earnings (loss)	**60**	39	**(546)**	343
Net earnings (loss) attributable to:				
TransAlta shareholders	**48**	28	**(583)**	305
Non-controlling interests	**12**	11	**37**	38
	60	39	**(546)**	343
Net earnings (loss) attributable to TransAlta shareholders	**48**	28	**(583)**	305
Preferred share dividends	**10**	4	**31**	15
Net earnings (loss) attributable to common shareholders	**38**	24	**(614)**	290
Weighted average number of common shares outstanding in the period *(millions)*	**255**	224	**235**	222
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.15**	0.11	**(2.61)**	1.31

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2012**	2011	**2012**	2011
Net earnings (loss)	**60**	39	**(546)**	343
Other comprehensive income (loss)				
Gains (losses) on translating net assets of foreign operations(1)	**13**	(11)	**(23)**	32
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(2)	**(12)**	9	**13**	(33)
Gains (losses) on derivatives designated as cash flow hedges, net of tax(3)	**7**	(65)	**(14)**	(103)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(4)	**2**	-	**5**	-
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax(5)	**(20)**	26	**(6)**	(177)
Net actuarial gains (losses) on defined benefit plans, net of tax(6)	**2**	(7)	**(27)**	(26)
Other comprehensive income of equity investees, net of tax(7)	**2**	-	**-**	-
Other comprehensive loss	**(6)**	(48)	**(52)**	(307)
Total comprehensive income (loss)	**54**	(9)	**(598)**	36
Total comprehensive income (loss) attributable to:				
Common shareholders	**44**	(4)	**(627)**	18
Non-controlling interests	**10**	(5)	**29**	18
	54	(9)	**(598)**	36

(1) Net of income tax expense of 2 and 2 for the three months and year ended Dec. 31, 2012 (2011 - nil), respectively.

(2) Net of income tax recovery of 1 and 2 expense for the three months and year ended Dec. 31, 2012 (2011 - 1 expense and 5 recovery), respectively.

(3) Net of income tax expense of nil and 3 for the three months and year ended Dec. 31, 2012 (2011 - 11 and 7 recovery), respectively.

(4) Net of income tax recovery of 1 and 2 for the three months and year ended Dec. 31, 2012 (2011 - nil), respectively.

(5) Net of income tax expense of 7 and 20 for the three months and year ended Dec. 31, 2012 (2011 - 5 recovery and 94 expense), respectively.

(6) Net of income tax recovery of nil and 10 for the three months and year ended Dec. 31, 2012 (2011 - 2 and 9 recovery), respectively.

(7) Net of income tax expense of 1 and nil for the three months and year ended Dec. 31, 2012 (2011 - nil), respectively.

TRANSALTA CORPORATION
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(in millions of Canadian dollars)

Unaudited	**Dec. 31, 2012**	Dec. 31, 2011
Cash and cash equivalents	**27**	49
Accounts receivable	**597**	541
Current portion of finance lease receivable	**2**	3
Collateral paid	**19**	45
Prepaid expenses	**7**	8
Risk management assets	**201**	391
Inventory	**82**	85
Income taxes receivable	**3**	2
	938	1,124
Investments	**172**	193
Long-term receivable	**-**	18
Finance lease receivable	**357**	42
Property, plant, and equipment		
Cost	**11,481**	11,386
Accumulated depreciation	**(4,437)**	(4,115)
	7,044	7,271
Goodwill	**447**	447
Intangible assets	**284**	276
Deferred income tax assets	**50**	169
Risk management assets	**69**	99
Other assets	**90**	90
Total assets	**9,451**	9,729
Accounts payable and accrued liabilities	**495**	463
Decommissioning and other provisions	**33**	99
Collateral received	**2**	16
Risk management liabilities	**167**	208
Income taxes payable	**6**	22
Dividends payable	**75**	67
Current portion of long-term debt	**607**	316
	1,385	1,191
Long-term debt	**3,610**	3,721
Decommissioning and other provisions	**279**	283
Deferred income tax liabilities	**430**	484
Risk management liabilities	**106**	142
Deferred credits and other long-term liabilities	**301**	281
Equity		
Common shares	**2,726**	2,273
Preferred shares	**781**	562
Contributed surplus	**9**	9
Retained earnings (deficit)	**(358)**	527
Accumulated other comprehensive loss	**(148)**	(102)
Equity attributable to shareholders	**3,010**	3,269
Non-controlling interests	**330**	358
Total equity	**3,340**	3,627
Total liabilities and equity	**9,451**	9,729

TRANSALTA CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Retained earnings (deficit)	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2010	2,204	293	7	431	185	3,120	431	3,551
Net earnings	-	-	-	305	-	305	38	343
Other comprehensive loss:								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(1)	(1)	-	(1)
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(260)	(260)	(20)	(280)
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(26)	(26)	-	(26)
Total comprehensive income						18	18	36
Common share dividends	-	-	-	(194)	-	(194)	-	(194)
Preferred share dividends	-	-	-	(15)	-	(15)	-	(15)
Distributions to non-controlling interests	-	-	-	-	-	-	(91)	(91)
Common shares issued	69	-	-	-	-	69	-	69
Preferred shares issued	-	269	-	-	-	269	-	269
Effect of share-based payment plans	-	-	2	-	-	2	-	2
Balance, Dec. 31, 2011	2,273	562	9	527	(102)	3,269	358	3,627
Net earnings (loss)	-	-	-	(583)	-	(583)	37	**(546)**
Other comprehensive loss:								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(10)	(10)	-	**(10)**
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(9)	(9)	(6)	**(15)**
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(27)	(27)	-	**(27)**
Total comprehensive income (loss)						(629)	31	**(598)**
Common share dividends	-	-	-	(271)	-	(271)	-	**(271)**
Preferred share dividends	-	-	-	(31)	-	(31)	-	**(31)**
Distributions to non-controlling interests	-	-	-	-	-	-	(59)	**(59)**
Common shares issued	453	-	-	-	-	453	-	**453**
Preferred shares issued	-	219	-	-	-	219	-	**219**
Balance, Dec. 31, 2012	**2,726**	**781**	**9**	**(358)**	**(148)**	**3,010**	**330**	**3,340**

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2012**	2011	**2012**	2011
Operating activities				
Net earnings (loss)	**60**	39	**(546)**	343
Depreciation and amortization	**145**	149	**564**	532
Gain on sale of assets	**-**	(13)	**(3)**	(16)
Accretion of provisions	**3**	4	**17**	19
Decommissioning and restoration costs settled	**(9)**	(10)	**(34)**	(33)
Deferred income tax expense	**7**	1	**90**	80
Unrealized (gain) loss from risk management activities	**(3)**	(15)	**99**	(175)
Unrealized foreign exchange (gain) loss	**(2)**	11	**5**	3
Provisions	**(6)**	-	**11**	22
Asset impairment charges	**-**	3	**324**	17
Sundance Units 1 and 2 impairment charge	**-**	-	**43**	-
Reserve on collateral	**-**	18	**-**	18
Equity loss, net of distributions received	**9**	17	**14**	1
Other non-cash items	**1**	(15)	**(12)**	(2)
Cash flow from operations before changes in working capital	**205**	189	**572**	809
Change in non-cash operating working capital balances	**40**	(2)	**(52)**	(119)
Cash flow from operating activities	**245**	187	**520**	690
Investing activities				
Additions to property, plant, and equipment	**(218)**	(135)	**(703)**	(453)
Additions to intangibles	**(12)**	(14)	**(39)**	(30)
Acquisition of finance lease	**-**	-	**(312)**	-
Proceeds on sale of property, plant, and equipment	**3**	9	**3**	12
Proceeds on sale of facilities and development projects	**-**	10	**3**	40
Acquisition of the remaining 50% of the Taylor Hydro joint venture	**-**	(7)	-	(7)
Resolution of certain outstanding tax matters	**-**	-	**9**	3
Realized losses on financial instruments	**(12)**	(7)	**(13)**	(12)
Net decrease in collateral received from counterparties	**(1)**	(13)	**(13)**	(109)
Net (increase) decrease in collateral paid to counterparties	**(3)**	(48)	**24**	(56)
Decrease in finance lease receivable	**1**	1	**3**	3
Other	**-**	1	**(8)**	(3)
Change in non-cash investing working capital balances	**16**	(5)	**(2)**	4
Cash flow used in investing activities	**(226)**	(208)	**(1,048)**	(608)
Financing activities				
Net increase (decrease) in borrowings under credit facilities	**(362)**	(200)	**152**	155
Repayment of long-term debt	**(2)**	(2)	**(314)**	(234)
Issuance of long-term debt	**388**	-	**388**	-
Dividends paid on common shares	**(18)**	(48)	**(104)**	(191)
Dividends paid on preferred shares	**(11)**	(4)	**(32)**	(15)
Net proceeds on issuance of common shares	**-**	1	**293**	2
Net proceeds on issuance of preferred shares	**-**	267	**217**	267
Realized gains (losses) on financial instruments	**(41)**	4	**(31)**	9
Distributions paid to subsidiaries' non-controlling interests	**(17)**	(17)	**(59)**	(61)
Other	**(1)**	2	**(6)**	(2)
Cash flow from (used in) financing activities	**(64)**	3	**504**	(70)
Cash flow from (used in) operating, investing, and financing activities	**(45)**	(18)	**(24)**	12
Effect of translation on foreign currency cash	**1**	1	**2**	2
Increase (decrease) in cash and cash equivalents	**(44)**	(17)	**(22)**	14
Cash and cash equivalents, beginning of period	**71**	66	**49**	35
Cash and cash equivalents, end of period	**27**	49	**27**	49
Cash income taxes paid (recovered)	**6**	5	**30**	(1)
Cash interest paid	**72**	70	**234**	197

SUPPLEMENTAL INFORMATION

		Dec. 31, 2012	Dec. 31, 2011
Closing market price (TSX) ($)		**15.12**	21.02
Price range for the last 12 months (TSX) ($)	High	**21.37**	23.24
	Low	**14.11**	19.45
Debt to invested capital (%)		**55.7**	52.5
Debt to invested capital excluding non-recourse debt (%)		**53.3**	50.0
Return on equity attributable to common shareholders (%)		**(23.7)**	10.6
Comparable return on equity attributable to common shareholders(1), (2) (%)		**4.6**	8.4
Return on capital employed(1) (%)		**(3.1)**	8.3
Comparable return on capital employed(1), (2) (%)		**5.3**	7.0
Cash dividends per share(1) ($)		**1.16**	1.16
Price to comparable earnings ratio(1) (times)		**30.2**	20.2
Earnings coverage(1) (times)		**(1.2)**	2.7
Dividend payout ratio based on net earnings(1) (%)		**(44.1)**	66.9
Dividend payout ratio based on comparable earnings(1), (2) (%)		**229.7**	84.3
Dividend payout ratio based on funds from operations(1), (2), (3) (%)		**34.9**	24.0
Dividend yield(1) (%)		**7.7**	5.5
Adjusted cash flow to debt(1), (3) (%)		**18.9**	20.1
Adjusted cash flow to interest coverage(1), (3) (times)		**4.4**	4.4

(1) Last 12 months

(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 news release.

(3) These ratios have been adjusted for the impact of the Sundance Units 1 and 2 arbitration.

RATIO FORMULAS

Debt to invested capital = long-term debt including current portion - cash and cash equivalents / long-term debt including current portion + non-controlling interests + equity attributable to shareholders - cash and cash equivalents

Return on equity attributable to common shareholders = net earnings attributable to common shareholders or earnings on a comparable basis / average 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 / average 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 common shareholders+ income taxes + net interest expense / interest on debt - interest income

Dividend payout ratio = common share dividends / net earnings attributable to common shareholders or earnings on a comparable basis or funds from operations

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 / average total debt - average 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 - 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.

British thermal units (Btu) - A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

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

Derate - To lower the rated electrical capability of a power generating facility or unit.

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.

Geothermal Plant - A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

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.

Net Maximum Capacity - The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

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

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

Spark Spread - A measure of gross margin per MW (sales price less cost of natural gas).

Turbine - A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

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

Uprate - To increase the rated electrical capability of a power generating facility or unit.

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

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