TRANSALTA CORPORATION
NEWS RELEASE

TransAlta announces seven percent increase in comparable earnings per share in 2011; files year end disclosure documents

- 2011 comparable earnings per share(1) increased seven per cent to $1.04 versus $0.97 in 2010
- Funds From Operations(1) of $809 million for the year
- Adjusted fleet availability of 88.2 per cent for the year

CALGARY, Alberta (Mar. 2, 2012) – TransAlta Corporation ("TransAlta") (TSX: TA; NYSE: TAC) today reported 2011 comparable earnings(1) of $230 million ($1.04 per share) versus $213 million ($0.97 per share) in 2010. Reported net earnings attributable to common shareholders for the year were $290 million ($1.31 per common share) compared to $255 million ($1.16 per common share) in 2010.

Improved comparable results were primarily driven by strong renewable resources throughout the year, the optimization of Centralia Thermal, the addition of Keephills 3 and increased Energy Trading gross margins. These results were partially offset by the unplanned outage at Genesee 3, increased operations maintenance and administration costs primarily due to higher trading compensation and productivity initiatives, and higher depreciation and interest expense primarily due to the commissioning of Keephills 3.

"We have improved our financial performance since 2009 by focusing on our base operations and adding quality generation assets in markets we know well," said Dawn Farrell, TransAlta President and CEO. "In 2012 we expect to add an additional 129 megawatts of generation from coal uprates and additional wind capacity. We also continue to advance a number of plans for growth in our core markets."

Reported net earnings attributable to common shareholders for the full year were higher primarily due to an increase in mark-to-market gains of $78 million on power hedges that no longer qualify for hedge accounting.

Funds from operations for the year were $809 million versus $805 million in 2010. Funds from operations were higher due to higher cash earnings. Cash flow from operations for the year was $694 million compared to $838 million in 2010 primarily due to the timing of payments and cash receipts and higher inventory.

Adjusted fleet availability for the full year was 88.2 per cent, taking into account the decision to economically dispatch Centralia Thermal, compared to 88.9 per cent in 2010. Adjusted fleet availability decreased due primarily to the shutdown of Sundance Units 1 and 2 prior to declaring economic destruction and due to the unplanned outage at our Genesee 3 facility in the fourth quarter. Unadjusted fleet availability for the year was 85.4 per cent compared to 88.9 per cent in 2010.

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(1) Comparable earnings per share, funds from operations, and comparable earnings are not defined under International Financial Reporting Standards ("IFRS"). Presenting these measures from period to period helps management and shareholders evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-IFRS Measures section of the extended 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.

In the fourth quarter of 2011, TransAlta reported comparable earnings of $29 million ($0.13 per share) compared to $80 million ($0.36 per share) in the fourth quarter of 2010. The decrease in comparable earnings was driven by lower Generation gross margins due primarily to higher penalties paid on Alberta Thermal outages under the applicable power purchase agreements, the unplanned outage at Genesee 3, and lower pricing in the Pacific Northwest. The fourth quarter of 2011 also had higher depreciation and interest expense primarily as a result of the commissioning of Keephills 3 and higher operations maintenance and administration costs due primarily to higher trading compensation and productivity initiatives. These results were partially offset through additional production from the commissioning of Keephills 3 and Energy Trading results.

Net earnings attributable to common shareholders for the fourth quarter of 2011 were $24 million ($0.11 per share). Fourth quarter 2011 net earnings were slightly lower than comparable earnings primarily due to booking an after-tax $13 million reserve on collateral on hand at MF Global Inc., partially offset by the sale of certain assets. With respect to MF Global Inc., the after-tax $13 million represents approximately 50 per cent of the total collateral on hand at MF Global Inc. In October 2011 MF Global Holding Ltd. filed for bankruptcy protection in the U.S. MF Global Holdings Ltd. is the parent company of MF Global Inc., which was used by TransAlta as a broker-dealer for certain commodity transactions. TransAlta continues to pursue recovery of these amounts but no assurance can be given as to the outcome.

Funds from operations in the fourth quarter of 2011 were $189 million, compared to $234 million earned in the same quarter in 2010. The decrease was driven by lower cash earnings in the quarter. Cash flow from operations for the fourth quarter of 2011 was $182 million compared to $317 million in 2010.

Fleet availability for the quarter was 90.3 per cent compared to 91.4 per cent in the fourth quarter of 2010. The decrease in availability is attributed to higher planned and unplanned outages at Alberta Thermal and the unplanned outage at Genesee 3. This was partially offset by lower planned outages at Genesee 3.

Subsequent Events

Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan

On February 21, TransAlta announced that it has added a Premium Dividend™ Component to its existing Dividend Reinvestment and Share Purchase Plan ("the Prior Plan"). The amended and restated plan is called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan").

The Plan provides eligible shareholders of TransAlta with two options, to reinvest dividends at a current three per cent discount towards the purchase of new shares of TransAlta or instead, to receive the equivalent to 102 per cent of the dividends payable in cash. Full details of the Plan are available on TransAlta's website at www.transalta.com under the Investor Centre.

Eligible shareholders are not required to participate in the Plan. Those shareholders who have not elected or been deemed to have elected to participate in the Plan will continue to receive their quarterly cash dividends in the usual manner.

To participate in the Plan, eligible shareholders must be resident in Canada. Residents of the United States or an individual who is otherwise a "U.S. Person" under applicable United States securities laws, may not participate in the Plan. Shareholders who are resident in any jurisdiction outside of Canada (other than the United States) may participate in the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that TransAlta is satisfied, in its sole discretion, that such laws do not subject the Plan, TransAlta, the Plan Agent or the Plan Broker to additional legal or regulatory requirements.

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 Management's Discussion and Analysis (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.

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 "Jess Nieukerk" as moderator.

Dial-in numbers:
For local Toronto participants – 1-416-340-2216
Toll-free North American participants – 1-866-226-1792

A link to the live webcast and presentation will be available via TransAlta's website, www.transalta.com, under the Investor Centre, Events & Presentations, Webcasts & Conference Calls section. If you are unable to participate in the call, the instant replay is accessible at 1-800-408-3053 with TransAlta pass code 5257384. 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 our geothermal, wind, hydro, natural gas and coal facilities in order to provide our customers with a reliable, low-cost source of power. For 100 years, TransAlta has been a responsible operator and a proud contributor to the communities where we work and live. TransAlta is recognized for its leadership on sustainability by the Dow Jones Sustainability North America Index, the FTSE4Good Index and the Jantzi Social Index. 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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BASIS OF PRESENTATION

On Jan. 1, 2011, we adopted International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises. Prior to the adoption of IFRS, we followed Canadian Generally Accepted Accounting Principles ("Canadian GAAP" or our "previous GAAP"). While IFRS has many similarities to Canadian GAAP, some of our accounting policies have changed as a result of our transition to IFRS. The most significant accounting policy changes that had an impact on the results of our operations are discussed within the applicable sections of this news release, and in more detail in the First-Time Adoption of IFRS section of this news release.

This news release should be read in conjunction with our 2011 audited consolidated financial statements and 2011 Annual Management's Discussion & Analysis ("MD&A"). In this news release, unless the context otherwise requires, 'we', 'our', 'us', 'the Corporation' and 'TransAlta' refers to TransAlta Corporation and our subsidiaries. The consolidated financial statements have been prepared in accordance with IFRS. All comparative figures have been restated using IFRS, unless otherwise noted. All tabular amounts in the following discussion are in millions of Canadian dollars, unless otherwise noted.

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 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 (Loss) Income ("AOCI") in the equity section of the Consolidated Statements of Financial Position.

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Availability (%)(1)	**90.3**	91.4	**85.4**	88.9
Production (GWh)(1)	**11,662**	12,757	**41,012**	48,614
Revenues	**701**	779	**2,663**	2,673
Gross margin(2)	**409**	451	**1,716**	1,488
Operating income(2)	**125**	199	**662**	487
Net earnings attributable to common shareholders	**24**	92	**290**	255
Net earnings per share attributable to common shareholders, basic and diluted	**0.11**	0.42	**1.31**	1.16
Comparable earnings per share(2)	**0.13**	0.36	**1.04**	0.97
Comparable EBITDA(2)	**273**	295	**1,077**	955
Funds from operations(2)	**189**	234	**809**	805
Funds from operations per share(2)	**0.84**	1.06	**3.64**	3.68
Cash flow from operating activities	**182**	317	**694**	838
Free cash flow(2)	**9**	56	**181**	172
Dividends paid per common share	**0.29**	0.29	**1.16**	1.16

As at	**Dec. 31, 2011**	Dec. 31, 2010
Total assets	**9,760**	9,635
Total long-term liabilities	**4,942**	5,009

AVAILABILITY & PRODUCTION

Availability for the three months ended Dec. 31, 2011 decreased compared to the same period in 2010 primarily due to higher planned and unplanned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities and higher unplanned outages at Genesee Unit 3, partially offset by lower planned outages at Genesee Unit 3.

Availability for the year ended Dec. 31, 2011 decreased compared to 2010 primarily due to higher planned and unplanned outages at Centralia Thermal and higher unplanned outages at Genesee Unit 3, partially offset by lower planned and unplanned outages at the Alberta coal PPA facilities and lower planned outages at Genesee Unit 3.

Production for the three months ended Dec. 31, 2011 decreased 1,095 gigawatt hours ("GWh") compared to the same period in 2010 due to the shut down at Sundance Units 1 and 2, higher planned and unplanned outages at the Alberta coal PPA facilities, the sale of the Meridian facility, lower PPA customer demand, and higher unplanned outages at Genesee Unit 3, partially offset by the commencement of commercial operations of Keephills Unit 3 in 2011, higher wind volumes, and lower planned outages at Genesee Unit 3.

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

(2) Gross margin, operating income, comparable earnings per share, comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), funds from operations, funds from operations per share, and free cash flow 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.

Production for the year ended Dec. 31, 2011 decreased 7,602 GWh compared to 2010 primarily due to the shut down at Sundance Units 1 and 2, higher planned and unplanned outages and higher economic dispatching at Centralia Thermal, the sale of the Meridian facility, the decommissioning of Wabamun, and higher unplanned outages at Genesee Unit 3, partially offset by the commencement of commercial operations of Keephills Unit 3 in 2011, lower planned and unplanned outages at the Alberta coal PPA facilities, higher wind volumes, higher hydro volumes, and lower planned outages at Genesee Unit 3.

The outages at Centralia Thermal did not negatively impact our gross margins for the year ended Dec. 31, 2011 as we were able to extend our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Availability for the whole fleet, after adjusting for the higher economic dispatching at Centralia, was 88.2 per cent for year ended Dec. 31, 2011, which is consistent with availability from the prior year.

NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings attributable to common shareholders for the three months and year ended Dec. 31, 2011 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Net earnings attributable to common shareholders, 2010	92	255
(Decrease) increase in Generation gross margins	(6)	54
Mark-to-market movements - Generation	(52)	78
Increase in Energy Trading gross margins	16	96
Increase in operations, maintenance, and administrative costs	(16)	(35)
Increase in depreciation expense	(16)	(18)
Increase in gain on sale of assets	13	16
Decrease in asset impairment charges	25	11
Increase in net interest expense	(16)	(37)
(Decrease) increase in equity earnings	(1)	7
Decrease (increase) in income tax expense	20	(82)
Increase in net earnings attributable to non-controlling interests	(7)	(14)
Increase in preferred share dividends	(3)	(14)
Increase in reserve on collateral	(18)	(18)
Other	(7)	(9)
Net earnings attributable to common shareholders, 2011	**24**	**290**

Generation gross margins, excluding the impact of mark-to-market movements, for the three months ended Dec. 31, 2011 decreased compared to the same period in 2010 primarily due to higher planned and unplanned outages at Alberta coal PPA facilities, lower recoveries from the Poplar Creek base plant that we no longer operate, higher unplanned outages at Genesee Unit 3, and unfavourable pricing related to penalties paid under Alberta PPAs during outages, partially offset by the commencement of commercial operations of Keephills Unit 3 in 2011 and lower planned outages at Genesee Unit 3.

For the year ended Dec. 31, 2011, Generation gross margins, excluding the impact of mark-to-market movements, increased compared to 2010 primarily due to higher hydro margins, the commencement of commercial operations of Keephills Unit 3 in 2011, higher wind volumes, lower planned and unplanned outages at the Alberta coal PPA facilities, and lower planned outages at Genesee Unit 3, partially offset by lower recoveries from the Poplar Creek base plant that we no longer operate, the sale of the Meridian facility, unfavourable pricing related to penalties paid under Alberta PPAs during outages, the decommissioning of Wabamun, and higher unplanned outages at Genesee Unit 3. The lower recoveries at the Poplar Creek base plant were offset by lower operations, maintenance, and administration ("OM&A") costs.

Mark-to-market movements decreased for the three months ended Dec. 31, 2011 compared to the same period in 2010 due to the recognition of unrealized gains resulting from certain hedges being deemed ineffective for accounting purposes during the fourth quarter of 2010.

Mark-to-market movements increased for the year ended Dec. 31, 2011 compared to 2010 due to the recognition of unrealized gains resulting from certain hedges being deemed ineffective for accounting purposes and increased weakening in market prices in the Pacific Northwest relative to our hedged prices.

For the three months ended Dec. 31, 2011, Energy Trading gross margins increased compared to the same period in 2010 principally due to strong trading results in the Western regions. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

Energy Trading gross margin increased for the year ended Dec. 31, 2011 compared to 2010 due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

OM&A costs for the three months ended Dec. 31, 2011 increased compared to the same periods in 2010 primarily due to higher compensation costs associated with favourable results in the Energy Trading Segment, costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

For the year ended Dec. 31, 2011, OM&A costs increased compared to 2010 due to higher compensation costs primarily associated with favourable results in the Energy Trading Segment, the writeoff of certain wind development costs and costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

Depreciation expense for the three months ended Dec. 31, 2011 increased compared to 2010 primarily due to an increased asset base, with the largest impact due to the commencement of commercial operations of Keephills Unit 3 in 2011.

For the year ended Dec. 31, 2011, depreciation expense increased compared to the same period in 2010 primarily due to an increased asset base, the impact of the 2010 decrease in Wabamun decommissioning and restoration costs, and the writedown of capital spares, partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Gain on sale of assets for the three months and year ended Dec. 31, 2011 increased compared to the same periods in 2010 due to the sale of the Meridian gas facility, the Grande Prairie biomass facility, and other development projects.

Asset impairment charges for the three months and year ended Dec. 31, 2011 decreased compared to the same period in 2010 due to impairment charges related to Sundance Units 1 and 2 and the Meridian facility recorded in 2010. Refer to the Asset Impairment Charges section of this news release for further details.

Net interest expense for the three months and year ended Dec. 31, 2011 increased compared to the same periods in 2010 due to lower capitalized interest, lower interest income related to the resolution of certain tax matters in 2010, and higher interest rates, partially offset by favourable foreign exchange rates and lower debt levels.

Equity earnings for the three months ended Dec. 31, 2011 were comparable to the same period in 2010.

For the year ended Dec. 31, 2011, equity earnings increased compared to 2010 primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

Income tax expense for the three months ended Dec. 31, 2011 decreased compared to the same period in 2010 due to lower earnings.

For the year ended Dec. 31, 2011, income tax expense increased compared to 2010 due to higher earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

Net earnings attributable to non-controlling interests for the three months and year ended Dec. 31, 2011 increased compared to the same periods in 2010 due to higher earnings at TransAlta Cogeneration, L.P. (“TA Cogen”).

The preferred share dividends for the three months and year ended Dec. 31, 2011 increased compared to the same periods in 2010 due to a higher balance of preferred shares outstanding during 2011. Preferred shares were issued in the fourth quarter of 2010 and there was an additional issuance in the fourth quarter of 2011.

A reserve on collateral was taken in the fourth quarter of 2011 related to collateral on hand at MF Global Inc. In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. The reserve was recognized due to uncertainty of collection of the collateral.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

Funds from operations for the three months ended Dec. 31, 2011 decreased $45 million compared to the same period in 2010 primarily due to lower net earnings.

For the year ended Dec. 31, 2011, funds from operations increased $4 million compared to 2010 primarily due to higher net earnings.

Free cash flow for the three months ended Dec. 31, 2011 decreased $47 million compared to the same period in 2010 due to the decrease in funds from operations and higher preferred share dividends.

For the year ended Dec. 31, 2011, free cash flow increased $9 million compared to 2010 due to the increase in funds from operations and lower common share dividends paid in cash as a result of increased participation in the Dividend Reinvestment and Share Purchase (“DRASP”) plan, partially offset by higher preferred share dividends and higher sustaining capital expenditures.

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 own and operate in are Western Canada, the Western U.S., and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity and natural gas upon our financial results, refer to our 2011 Annual MD&A.

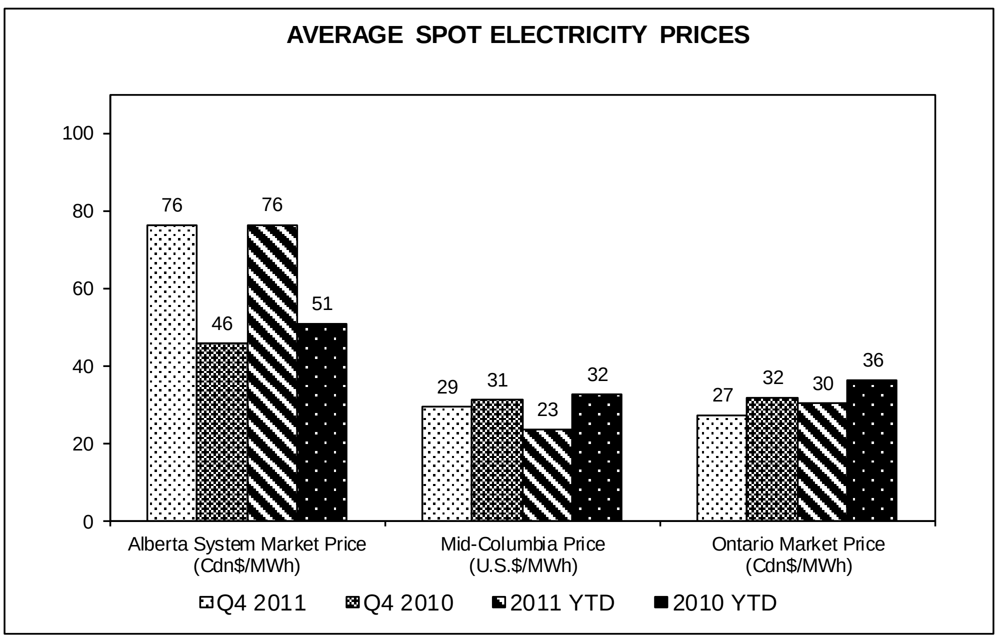
Contracted Cash Flows

During the year, approximately 93 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2011 ranging from $65 to $70 per megawatt hour (“MWh”) in Alberta, and from U.S.$50 to $55 per MWh in the Pacific Northwest.

Electricity Prices

Please refer to the Business Environment section of our 2011 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 risk associated with changes in those prices.

The average spot electricity prices for the three months and years ended Dec. 31, 2011 and 2010 in our three major markets are shown in the following graphs.



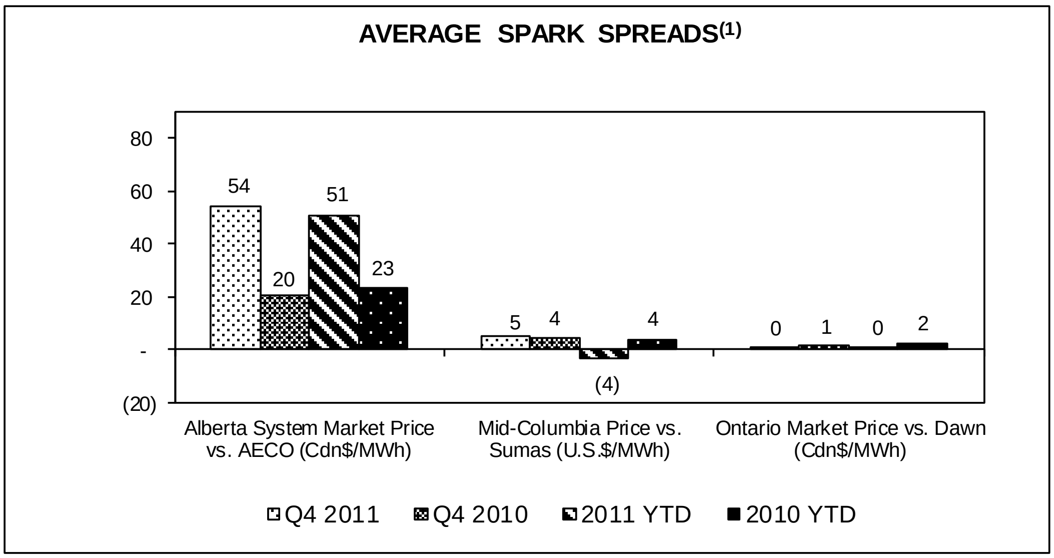
For the three months ended Dec. 31, 2011, average spot prices increased in Alberta due to load growth from the prior year and supply tightening in the market. In the Pacific Northwest and Ontario, average spot prices decreased compared to the same periods in 2010 due to lower natural gas prices.

For the year ended Dec. 31, 2011, average spot prices increased in Alberta due to load growth from the prior year and supply tightening in the market. In the Pacific Northwest and Ontario, average spot prices decreased compared to 2010 due to lower natural gas prices and increased hydro generation in both regions.

Spark Spreads

Please refer to the Business Environment section of our 2011 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 years ended Dec. 31, 2011 and 2010 in our three major markets are shown in the following graphs.



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

For the three months and year ended Dec. 31, 2011, average spark spreads increased in Alberta due to higher power prices. In the Pacific Northwest, average spark spreads in the fourth quarter increased due to lower natural gas prices. In Ontario, spark spreads decreased as power prices weakened more than natural gas prices.

For the year ended Dec. 31, 2011, average spark spreads increased in Alberta due to higher power prices. In the Pacific Northwest, average spark spreads decreased due to strong hydro generation, which caused power prices to decrease more than natural gas prices compared to 2010. In Ontario, spark spreads decreased as power prices weakened more than natural gas prices.

DISCUSSION OF SEGMENTED RESULTS

Our operating results by segment are presented below:

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**
Taxes, other than income taxes	**6**	**-**	**-**	**6**
Intersegment cost allocation	**2**	**(2)**	**-**	**-**
Operating expenses	**245**	**14**	**25**	**284**
Operating income	**124**	**26**	**(25)**	**125**
Finance lease income	**2**	**-**	**-**	**2**
Equity loss	**(2)**	**-**	**-**	**(2)**
Gain on sale of assets	**13**	**-**	**-**	**13**
Asset impairment charges	**(3)**	**-**	**-**	**(3)**
Reserve on collateral	**-**	**(18)**	**-**	**(18)**
Foreign exchange loss				**(3)**
Net interest expense				**(64)**
Earnings before income taxes				**50**

3 months ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Revenues	755	24	-	779
Fuel and purchased power	328	-	-	328
Gross margin	427	24	-	451
Operations, maintenance, and administration	107	4	18	129
Depreciation and amortization	111	1	5	117
Taxes, other than income taxes	6	-	-	6
Intersegment cost allocation	1	(1)	-	-
Operating expenses	225	4	23	252
Operating income	202	20	(23)	199
Finance lease income	2	-	-	2
Equity loss	(1)	-	-	(1)
Asset impairment charges	(28)	-	-	(28)
Foreign exchange gain				4
Net interest expense				(48)
Earnings before income taxes				128

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**
Taxes, other than income taxes	**27**	**-**	**-**	**27**
Intersegment cost allocation	**8**	**(8)**	**-**	**-**
Operating expenses	**914**	**36**	**104**	**1,054**
Operating income	**665**	**101**	**(104)**	**662**
Finance lease income	**8**	**-**	**-**	**8**
Equity income	**14**	**-**	**-**	**14**
Gain on sale of assets	**16**	**-**	**-**	**16**
Asset impairment charges	**(17)**	**-**	**-**	**(17)**
Reserve on collateral	**-**	**(18)**	**-**	**(18)**
Other income				**2**
Foreign exchange loss				**(3)**
Net interest expense				**(215)**
Earnings before income taxes				**449**

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Revenues	2,632	41	-	2,673
Fuel and purchased power	1,185	-	-	1,185
Gross margin	1,447	41	-	1,488
Operations, maintenance, and administration	424	17	69	510
Depreciation and amortization	443	2	19	464
Taxes, other than income taxes	27	-	-	27
Intersegment cost allocation	5	(5)	-	-
Operating expenses	899	14	88	1,001
Operating income	548	27	(88)	487
Finance lease income	8	-	-	8
Equity income	7	-	-	7
Asset impairment charges	(28)	-	-	(28)
Foreign exchange gain				8
Net interest expense				(178)
Earnings before income taxes				304

GENERATION: *TransAlta owns and operates hydro, wind, natural gas- 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 2011 Annual MD&A.*

Due to our transition to IFRS, our interest in the Fort Saskatchewan generating facility is now accounted for as a finance lease and our interests in the CE Generation, LLC ("CE Gen") and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures are now accounted for using the equity method. Accordingly, the related operational and financial results of these facilities are no longer included in the results of our Western Canada and International geographical regions, respectively. Under Canadian GAAP, these assets were proportionately consolidated. Although these assets no longer contribute to the operating income of the Generation Segment for accounting purposes, it is management's view that these facilities still form part of our Generation Segment. Please refer to the Finance Lease and Equity Investments sections of the Generation Segment discussion of this news release for further details.

GENERATION OPERATIONS*:* *During 2011, we began commercial operations at Keephills Unit 3, a 450 megawatt ("MW") supercritical coal-fired plant in Alberta, of which we have a 50 per cent ownership interest, and at Bone Creek, a 19 MW hydro facility in British Columbia. At Dec. 31, 2011, our generating assets had 8,174 MW of gross generating capacity*[(1)] *in operation (7,831 MW net ownership interest) and 129 MW net under construction. 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 Operation are as follows:

	2011				2010	
3 months ended Dec. 31	**Total**	**Comparable adjustments**[(2)]	**Comparable total**[(2)]	**Per installed MWh**	Comparable total[(2)]	Per installed MWh
Revenues	**661**	**(2)**	**659**	**36.52**	712	37.28
Fuel and purchased power	**292**	**-**	**292**	**16.18**	328	17.18
Gross margin	**369**	**(2)**	**367**	**20.34**	384	20.10
Operations, maintenance, and administration	**110**	**(1)**	**109**	**6.04**	107	5.60
Depreciation and amortization	**127**	**-**	**127**	**7.04**	111	5.81
Taxes, other than income taxes	**6**	**-**	**6**	**0.33**	6	0.31
Intersegment cost allocation	**2**	**-**	**2**	**0.11**	1	0.05
Operating expenses	**245**	**(1)**	**244**	**13.52**	225	11.77
Operating income	**124**	**(1)**	**123**	**6.82**	159	8.33
Installed capacity (GWh)	**18,047**		**18,047**		19,097	
Production (GWh)	**11,158**		**11,158**		12,200	
Availability (%)	**90.2**		**90.2**		91.0	

(1) We measure capacity as net maximum capacity (see glossary for definition of this and other key items) 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.

Year ended Dec. 31	2011 Total	2011 Comparable adjustments[1]	2011 Comparable total[1]	2011 Per installed MWh	2010 Comparable total[1]	2010 Per installed MWh
Revenues	**2,526**	**(127)**	**2,399**	**33.94**	2,589	34.26
Fuel and purchased power	**947**	**-**	**947**	**13.40**	1,185	15.68
Gross margin	**1,579**	**(127)**	**1,452**	**20.54**	1,404	18.58
Operations, maintenance and administration	**419**	**(6)**	**413**	**5.84**	424	5.61
Depreciation and amortization	**460**	**(4)**	**456**	**6.45**	443	5.86
Taxes, other than income taxes	**27**	**-**	**27**	**0.38**	27	0.36
Intersegment cost allocation	**8**	**-**	**8**	**0.11**	5	0.07
Operating expenses	**914**	**(10)**	**904**	**12.78**	899	11.90
Operating income	**665**	**(117)**	**548**	**7.76**	505	6.68
Installed capacity (GWh)	**70,681**		**70,681**		75,559	
Production (GWh)	**38,911**		**38,911**		46,416	
Availability (%)	**84.8**		**84.8**		88.5	

Generation Production and Comparable Gross Margins[1]

Production volumes, comparable revenues[1], fuel and purchased power costs, and comparable gross margins[1] based on geographical regions and fuel types are presented below.

3 months ended Dec. 31, 2011	**Production (GWh)**	**Installed (GWh)**	**Revenue[2]**	**Fuel & purchased power**	**Gross margin[2]**	**Revenue per installed MWh[2]**	**Fuel & purchased power per installed MWh**	**Gross margin per installed MWh[2]**
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**

(1) 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.

(2) Amounts represent comparable figures.

3 months ended Dec. 31, 2010	Production (GWh)	Installed (GWh)	Revenue[1]	Fuel & purchased power	Gross margin[1]	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh	Gross margin per installed MWh[1]
Coal	6,418	7,744	221	97	124	28.54	12.53	16.01
Gas	898	1,084	61	19	42	56.27	17.53	38.74
Renewables	705	2,904	45	3	42	15.50	1.03	14.47
Total Western Canada	8,021	11,732	327	119	208	27.87	10.14	17.73
Gas	946	1,656	111	60	51	67.03	36.23	30.80
Renewables	424	1,459	40	2	38	27.42	1.37	26.05
Total Eastern Canada	1,370	3,115	151	62	89	48.48	19.90	28.58
Coal	2,443	3,039	205	135	70	67.46	44.42	23.04
Gas	366	1,211	29	12	17	23.95	9.91	14.04
Total International	2,809	4,250	234	147	87	55.06	34.59	20.47
	12,200	19,097	712	328	384	37.28	17.18	20.10

Year ended Dec. 31, 2011	**Production (GWh)**	**Installed (GWh)**	**Revenue[1]**	**Fuel & purchased power**	**Gross margin[1]**	**Revenue per installed MWh[1]**	**Fuel & purchased power per installed MWh**	**Gross margin per installed MWh[1]**
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**

Year ended Dec. 31, 2010	Production (GWh)	Installed (GWh)	Revenue[1]	Fuel & purchased power	Gross margin[1]	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh	Gross margin per installed MWh[1]
Coal	25,025	31,325	813	331	482	25.95	10.57	15.38
Gas	3,493	4,246	222	76	146	52.28	17.90	34.38
Renewables	2,506	11,120	142	10	132	12.77	0.90	11.87
Total Western Canada	31,024	46,691	1,177	417	760	25.21	8.93	16.28
Gas	3,816	6,570	435	243	192	66.21	36.99	29.22
Renewables	1,330	5,435	126	7	119	23.18	1.29	21.89
Total Eastern Canada	5,146	12,005	561	250	311	46.73	20.82	25.91
Coal	8,594	12,057	730	469	261	60.55	38.90	21.65
Gas	1,652	4,806	121	49	72	25.18	10.20	14.98
Total International	10,246	16,863	851	518	333	50.47	30.72	19.75
	46,416	75,559	2,589	1,185	1,404	34.26	15.68	18.58

(1) Amounts represent comparable figures.

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 2011 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, 2011 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2010	8,021	31,024
Shut down at Sundance Units 1 and 2	(924)	(3,543)
Sale of Meridian	(164)	(719)
Decommissioning of Wabamun	-	(473)
Lower PPA customer demand	(156)	(293)
Higher unplanned outages at Genesee Unit 3	(287)	(287)
Market curtailments	(28)	(272)
Higher planned and unplanned outages at natural gas-fired facilities	(55)	(199)
Commencement of commercial operations of Keephills Unit 3	480	639
(Higher) lower planned and unplanned outages at the Alberta coal PPA facilities	(321)	403
Higher wind volumes	136	389
(Lower) higher hydro volumes	(25)	343
Lower planned outages at Genesee Unit 3	219	219
Higher production at natural gas-fired facilities	41	50
Other	(13)	19
Production, 2011	**6,924**	**27,300**

The primary factors contributing to the change in comparable gross margin(1) for the three months and year ended Dec. 31, 2011 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Comparable gross margin(1), 2010	208	760
Higher hydro margins	3	52
Commencement of commercial operations of Keephills Unit 3	28	41
(Higher) lower planned and unplanned outages at the Alberta coal PPA facilities	(26)	14
Higher wind volumes	5	14
Lower planned outages at Genesee Unit 3	10	10
Poplar Creek base plant no longer operated by TransAlta	(19)	(57)
Sale of Meridian	(3)	(15)
Unfavourable pricing, net of any penalties paid under the Alberta PPAs during outages	(5)	(14)
Higher unplanned outages at Genesee Unit 3	(14)	(14)
Decommissioning of Wabamun	-	(10)
Higher planned and unplanned outages at natural gas-fired facilities	(1)	(5)
Other	(2)	2
Comparable gross margin(1), 2011	**184**	**778**

The lower recoveries at the Poplar Creek base plant identified in the table above were offset by lower OM&A costs.

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

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2011 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, 2011 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2010	1,370	5,146
Higher outages at natural gas-fired facilities	(59)	(131)
Unfavourable market conditions at natural gas-fired facilities	(31)	(89)
Higher wind volumes	72	201
Other	(11)	(28)
Production, 2011	**1,341**	**5,099**

The primary factors contributing to the change in gross margin for the three months and year ended Dec. 31, 2011 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Gross margin, 2010	89	311
Higher wind volumes	7	21
Higher outages at natural gas-fired facilities	-	(3)
Other	5	2
Gross margin, 2011	**101**	**331**

International

Our International assets consist of coal and natural gas facilities in various locations in the United States, and natural gas assets in Australia. Refer to the Discussion of Segmented Results section of our 2011 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, 2011 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2010	2,809	10,246
Lower (higher) unplanned outages at Centralia Thermal	45	(1,892)
Lower (higher) economic dispatching at Centralia Thermal	76	(910)
Higher planned outages at Centralia Thermal	-	(658)
Lower production at natural gas-fired facilities	(16)	(249)
Other	(21)	(25)
Production, 2011	**2,893**	**6,512**

The primary factors contributing to the change in comparable gross margin[1] for the three months and year ended Dec. 31, 2011 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Comparable gross margin[1], 2010	87	333
(Unfavourable) favourable pricing, primarily driven by lower purchased power prices	(9)	19
Favourable foreign exchange	2	1
Lower production at Centralia Thermal	-	(3)
Other	2	(7)
Comparable gross margin[1], 2011	**82**	**343**

The outages at Centralia Thermal did not negatively impact our gross margins as we were able to extend our planned outage to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

Operations, Maintenance, and Administration Expense

OM&A costs for the three months ended Dec. 31, 2011 increased compared to the same period in 2010 due to costs associated with several productivity initiatives and the commencement of commercial operations of Keephills Unit 3, partially offset by reduced costs associated with the discontinuation of management of the base plant at Poplar Creek.

For the year ended Dec. 31, 2011, OM&A costs decreased compared to 2010 due to lower costs associated with the discontinuation of managing the base plant at Poplar Creek, partially offset by the writeoff of certain wind development costs, costs associated with several productivity initiatives and the commencement of commercial operations of Keephills Unit 3.

Depreciation Expense

The primary factors contributing to the change in depreciation expense for the three months and year ended Dec. 31, 2011 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Depreciation and amortization expense, 2010	111	443
Increase in asset base	15	25
Impact of decrease in estimated decommissioning and restoration costs at Wabamun in prior year	1	6
Writedown of capital spares	-	4
Change in residual values	(3)	(13)
Sale of Meridian	(1)	(7)
Unfavourable (favourable) foreign exchange	2	(4)
Other	2	6
Depreciation and amortization expense, 2011	**127**	**460**

(1) 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.

ASSET IMPAIRMENT CHARGES

During 2011, we recorded a pre-tax impairment charge of $17 million related to four Generation assets within the renewables fleet that were part of the acquisition of Canadian Hydro Developers, Inc. (“Canadian Hydro”), in order to write the assets down to their estimated fair values less cost to sell. The fair value estimates are derived from the long-range forecasts for the assets and prices evidenced in the marketplace. Two of the assets were impaired due to operational factors that impacted their useful lives, resulting in an impairment charge of $5 million. The impairment charges on the other two assets, totalling $12 million, resulted from our annual comprehensive impairment assessment and reflect lower forecast pricing at these merchant facilities.

During 2010, we recorded a pre-tax impairment charge of $28 million ($21 million after deducting the amount that was attributed to the non-controlling interest) on certain Generation assets, consisting of a $7 million charge against the natural gas fleet and a $21 million charge against the coal fleet. The natural gas fleet impairment reflects the sale of our 50 per cent interest in the Meridian facility, which was attributed to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and resulted from the shut down due to the physical state of the boilers, such that the units cannot be economically restored to service under the terms of the PPA.

FINANCE LEASE

Although we continue to operate the Fort Saskatchewan facility, our long-term contract was determined to be a finance lease under IFRS, as the principal risks and rewards of ownership have been transferred to the customer. As a result, the assets subject to the lease have been removed from property, plant, and equipment (“PP&E”) and the amounts due under the lease have been recorded in the Consolidated Statements of Financial Position as a finance lease receivable. Under Canadian GAAP, we had proportionately consolidated our interest in the financial and operational results of the Fort Saskatchewan facility. Please refer to *Note 6* of our audited consolidated financial statements within our 2011 Annual Report for additional information regarding our finance lease.

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Availability (%)	**100.4**	101.2	**98.1**	97.1
Production (GWh)	**130**	120	**481**	488

Availability for the three months and year ended Dec. 31, 2011 was comparable to the same periods in 2010.

Production for the three months ended Dec. 31, 2011 increased by 10 GWh compared to the same period in 2010 due to higher customer demand.

For the year ended Dec. 31, 2011, production decreased by 7 GWh compared to 2010 primarily due to lower customer demand partially offset by lower planned outages.

Finance lease income for the three months and year ended Dec. 31, 2011 was consistent with the same periods in 2010 at $2 million and $8 million, respectively.

EQUITY INVESTMENTS

Under IFRS, interests in joint ventures that are jointly controlled entities, like our CE Gen and Wailuku joint ventures, can be recognized using either the proportionate consolidation or equity method. We adopted the equity method to account for these interests to align with the requirements of IFRS 11 *Joint Arrangements* ("IFRS 11"), which was issued by the International Accounting Standards Board in May 2011. Under Canadian GAAP, we had proportionately consolidated our interests in the financial and operational results of CE Gen and Wailuku.

This change resulted in the reclassification of our share of assets and liabilities from each respective line item on our Consolidated Statements of Financial Position to a single line item entitled "Investments". Our proportionate share of revenue and expenses was also reclassified from each respective line item and presented as a single amount entitled "Equity (loss) income" on the Consolidated Statements of Earnings. Please refer to *Note 7* of our audited consolidated financial statements within our 2011 Annual Report for additional financial information regarding our equity accounted investments.

Our investments accounted for under the equity method 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 from our investments accounted for under the equity method:

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Availability (%)	**90.5**	98.5	**94.9**	95.5
Production (GWh)				
Gas	**24**	84	**308**	411
Renewables	**350**	353	**1,312**	1,299
Total production	**374**	437	**1,620**	1,710

Availability for the three months and year ended Dec. 31, 2011 decreased compared to the same periods in 2010 due to higher planned and unplanned outages at our CE Gen facilities.

Production for the three months and year ended Dec. 31, 2011 decreased compared to the same periods in 2010 due to unfavourable market conditions and higher planned and unplanned outages.

During the three months ended Dec. 31, 2011, our equity earnings from CE Gen and Wailuku were comparable to the same period in 2010.

Equity earnings from CE Gen and Wailuku for the year ended Dec. 31, 2011 were $14 million as compared to income of $7 million for 2010. The equity earnings increased primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

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 2011 Annual MD&A for further discussion on VaR.*

Energy Trading manages available generating capacity, as well as the fuel and transmission needs, of the Generation Segment by utilizing contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. 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 2011 Annual MD&A.

The results of the Energy Trading Segment are as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Revenues	**40**	24	**137**	41
Fuel and purchased power	**-**	-	**-**	-
Gross margin	**40**	24	**137**	41
Operations, maintenance, and administration	**16**	4	**43**	17
Depreciation and amortization	**-**	1	**1**	2
Intersegment cost recovery	**(2)**	(1)	**(8)**	(5)
Operating expenses	**14**	4	**36**	14
Operating income	**26**	20	**101**	27

For the three months ended Dec. 31, 2011, gross margins increased compared to the same period in 2010 principally due to strong trading results in the Western regions. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

Gross margin increased for the year ended Dec. 31, 2011 compared to 2010 primarily due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

OM&A costs for the three months and year ended Dec. 31, 2011 increased compared to the same periods in 2010 due to higher compensation costs associated with favourable results and costs associated with several productivity initiatives.

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	
	2011	2010	**2011**	2010
Operations, maintenance, and administration	**19**	18	**83**	69
Depreciation and amortization	**6**	5	**21**	19
Operating expenses	**25**	23	**104**	88

During the three months ended Dec. 31, 2011, OM&A costs were comparable to the same period in 2010.

OM&A costs increased for the year ended Dec. 31, 2011 compared to 2010 due to costs associated with several productivity initiatives and higher compensation costs.

NET INTEREST EXPENSE

Under IFRS, where discounting is used, the increase in the carrying amount of a provision, such as for decommissioning and restoration activities, associated with the passage of time is recognized as a finance cost and included in net interest expense. Under Canadian GAAP, this was recognized as part of depreciation and amortization expense or fuel and purchased power.

The components of net interest expense are shown below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Interest on debt	**60**	58	**228**	226
Interest income	**-**	(2)	**-**	(18)
Capitalized interest	**-**	(13)	**(31)**	(48)
Ineffectiveness on fair value hedges	**-**	-	**(1)**	-
Interest expense	**60**	43	**196**	160
Accretion of provisions	**4**	5	**19**	18
Net interest expense	**64**	48	**215**	178

The change in net interest expense for the three months and year ended Dec. 31, 2011, compared to the same period in 2010 is shown below:

	3 months ended Dec. 31	Year ended Dec. 31
Net interest expense, 2010	48	178
Lower interest income primarily due to the resolution of certain outstanding tax matters in 2010	3	18
Lower capitalized interest	13	17
Higher interest rates	3	10
Higher decommissioning and restoration accretion	-	1
Favourable foreign exchange	-	(4)
Lower debt levels	(4)	(5)
Ineffective gain on fair value hedges	-	(1)
Higher financing costs	1	1
Net interest expense, 2011	**64**	**215**

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	
	2011	2010	**2011**	2010
Earnings before income taxes	**50**	128	**449**	304
Income attributable to non-controlling interests	**(11)**	(4)	**(38)**	(24)
Equity loss (income)	**2**	1	**(14)**	(7)
Impacts associated with certain de-designated and ineffective hedges	**(2)**	(43)	**(127)**	(43)
Asset impairment charges	**3**	28	**17**	28
Gain on sale of facilities and development projects	**(13)**	-	**(16)**	-
Reserve on collateral	**18**	-	**18**	-
Other non-comparable items	**1**	-	**10**	-
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**48**	110	**299**	258
Income tax expense	**11**	31	**106**	24
Income tax expense related to impacts associated with certain de-designated and ineffective hedges	**(1)**	(15)	**(46)**	(15)
Income tax recovery related to asset impairment charges	**1**	12	**4**	12
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	30
Income tax expense related to gain on sale of facilities and development projects	**(3)**	-	**(4)**	-
Income tax recovery related to reserve on collateral	**5**	-	**5**	-
Reclassification of Part VI.1 tax	**(2)**	-	**(2)**	-
Income tax recovery related to other non-comparable items	**-**	-	**3**	-
Income tax expense excluding non-comparable items	**11**	28	**66**	51
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items (%)	**23**	25	**22**	20

The income tax expense excluding non-comparable items for the three months ended Dec. 31, 2011 decreased compared to the same period in 2010 due to lower comparable earnings.

For the year ended Dec. 31, 2011, income tax expense excluding non-comparable items increased compared to 2010 due to higher comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three months ended Dec. 31, 2011 decreased compared to the same period in 2010 due to lower comparable earnings.

For the year ended Dec. 31, 2011, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items increased compared to 2010 due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

NON-CONTROLLING INTERESTS

As a result of our transition to IFRS, the non-controlling interest related to our proportionate share of ownership in the Saranac facility is reported as part of our net investment in CE Gen. Please refer to the Equity Investments section of this news release for further discussion.

Net earnings attributable to non-controlling interests for the three months and year ended Dec. 31, 2011 increased $7 million and $14 million, respectively, compared to the same periods in 2010 due to higher earnings at TA Cogen.

STATEMENTS OF CASH FLOWS

Our transition to IFRS changed the presentation of several items on the Consolidated Statements of Cash Flows. The most significant of these items is the effect of using the equity method instead of the proportionate consolidation method to account for our interests in CE Gen and Wailuku. Our share of CE Gen's and Wailuku's cash and cash equivalents and cash flow changes are no longer presented within each line item of the operating, investing, or financing activities sections of the Consolidated Statements of Cash Flows, and instead, cash distributions received are presented as an operating activity and cash returns of invested capital or additional cash invested are presented as an investing activity. The capitalization of costs associated with planned major maintenance and inspection activities that were previously expensed under Canadian GAAP will result in these cash expenditures being reported as an investing activity under IFRS. Under Canadian GAAP these expenditures impacted cash flow from operations.

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the three months and year ended Dec. 31, 2011 compared to the same periods in 2010:

3 months ended Dec. 31	**2011**	2010	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**66**	57	
Provided by (used in):			
Operating activities	**182**	317	Lower cash earnings of $45 million and unfavourable changes in working capital balances of $90 million primarily due to the timing of payments and receipts
Investing activities	**(204)**	(213)	Decrease in additions to PP&E of $58 million, increase in collateral received from counterparties of $26 million, and proceeds on the sale of facilities and development projects of $10 million, offset by an increase in collateral paid to counterparties of $52 million, a decrease of $15 million in proceeds on the sale of the minority interest in Kent Hills, and a decrease of $17 million due to the resolution of certain tax matters in 2010
Financing activities	**4**	(122)	Lower net repayments on long-term debt, offset by a decrease in proceeds on issuance of preferred shares of $24 million
Translation of foreign currency cash	**1**	(4)	
Cash and cash equivalents, end of period	**49**	35	

Year ended Dec. 31	**2011**	2010	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**35**	53	
Provided by (used in):			
Operating activities	**694**	838	Unfavourable changes in working capital balances of $148 million primarily due to the timing of payments and receipts offset by higher cash earnings of $4 million
Investing activities	**(615)**	(765)	Decrease in additions to PP&E of $355 million and proceeds on the sale of facilities and development projects of $40 million, offset by a $156 million decrease in collateral received from counterparties, an increase of $54 million in collateral paid to counterparties, a decrease of $15 million in proceeds on the sale of the minority interest in Kent Hills, and a decrease of $26 million due to the resolution of certain tax matters in 2010
Financing activities	**(67)**	(90)	Lower net debt repayments, decrease in cash dividends paid on common shares of $25 million, offset by a decrease in proceeds on issuance of preferred shares of $24 million and an increase in dividends paid on preferred shares of $15 million
Translation of foreign currency cash	**2**	(1)	
Cash and cash equivalents, end of period	**49**	35	

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

At Dec. 31, 2011, we had 223.6 million (2010 - 220.3 million) common shares issued and outstanding. During the three months ended Dec. 31, 2011, 0.7 million (2010 - 0.8 million) common shares were issued for $17 million (2010 - $23 million). All of the shares issued for the three months were issued under the DRASP plan. Of the 0.8 million common shares issued during the three months ended Dec. 31, 2010, 0.7 million were issued for $19 million under the terms of the DRASP plan and 0.1 million were issued for $4 million under the Performance Share Ownership Plan ("PSOP"). During the year ended Dec. 31, 2011, 3.3 million (2010 - 1.9 million) common shares were issued for $69 million (2010 - $40 million). Of the 3.3 million common shares issued during the year ended Dec. 31, 2011, 0.1 million were issued for cash proceeds of $2 million and 3.2 million were issued for $67 million under the terms of the DRASP plan. Of the 1.9 million common shares issued during the year ended Dec. 31, 2010, 0.1 million were issued for cash proceeds of $1 million, 1.6 million were issued for $35 million under the terms of the DRASP plan, and 0.2 million were issued for $4 million under PSOP.

At Dec. 31, 2011, we had 23.0 million (2010 - 12.0 million) preferred shares issued and outstanding. During the year ended Dec. 31, 2011, 11.0 million (2010 - 12.0 million) Series C Preferred Shares were issued for $269 million, net of after-tax issuance costs of $6 million (2010 - $293 million, net of after-tax issuance costs of $7 million).

We employ a variety of stock-based compensation to align employee and corporate objectives. At Dec. 31, 2011, we had 1.7 million outstanding employee stock options (2010 - 2.2 million). During the three months ended Dec. 31, 2011, 0.1 million options expired, or were exercised or cancelled (2010 - a nominal number of options expired, or were exercised or cancelled). During the year ended Dec. 31, 2011, 0.5 million options expired, or were exercised or cancelled (2010 - 0.2 million options expired, or were exercised or cancelled).

2012 OUTLOOK

Business Environment

Power Prices

In 2012, power prices in Alberta are expected to be in line with 2011, driven by continued load growth, partially offset by lower natural gas prices. In the Pacific Northwest, we continue to expect weak prices due to low natural gas prices and slow load growth.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has indicated its intention to regulate greenhouse gas emissions from coal-fired power units by 2015. This regulatory framework is under discussion between the federal and provincial governments and the industry, and is expected to be finalized in 2012.

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 in 2012, but will not directly affect our coal-fired operations in Washington State. TransAlta's agreement with Washington State, established in March 2011, provides regulatory clarity regarding an emissions regime related to the Centralia Coal plant until 2025.

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. More 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 improvement in 2011 and we expect this trend to continue through 2012 at a slow to moderate pace. We continue to monitor global events, including conditions in Europe, and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no counterparty losses in 2011, 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.

In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. MF Global Inc. has not filed for bankruptcy but, under the U.S. Securities Investor Protection Act, the Securities Investor Protection Corp. is overseeing a liquidation of the broker-dealer to return assets to customers. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of our collateral relates to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and is subject to a dispute between the U.S. trustee and the U.K. administrator. We have collateral of approximately $36 million with MF Global Inc. and due to the uncertainty of collection, we have recognized an $18 million reserve against the collateral that had been posted. The net amount of the collateral has been reclassified to a long-term asset.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase for 2012 due to the completion of New Richmond and the three uprates at our Alberta PPA facilities. Prior to the effect of any economic dispatching, overall production is expected to increase for 2012 due to a full year of operating Keephills Unit 3 and lower unplanned outages, offset by higher than normal major maintenance outages scheduled in the Alberta Thermal fleet in 2012. Overall availability is expected to be in the range of 89 to 90 per cent in 2012 due to lower unplanned outages.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average approximately 70 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis, we target being up to 90 per cent contracted for the upcoming year, stepping down to 65 per cent in the fourth year. As at the end of 2011, approximately 86 per cent of our 2012 capacity was contracted. The average price of our short-term physical and financial contracts for 2012 ranges from $60 to $65 per MWh in Alberta, and from U.S.$50 to U.S.$55 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2012, on a standard cost basis, are expected to increase by approximately four per cent compared to 2011 due to the drivers mentioned above.

Although we own the Centralia mine in the State of Washington, it currently is not 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 2012 is expected to increase by approximately nine per cent due to higher diesel, commodity costs, and coal dust mitigation expenses.

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 risk.

Operations, Maintenance, and Administration Costs

OM&A costs for 2012 are expected to be approximately five per cent lower than 2011 OM&A.

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 to maximize earnings while still maintaining an acceptable risk profile. Our 2012 objective is for Energy Trading to contribute between $65 million and $85 million in gross margin.

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 2012 is expected to be higher than our reported 2011 net interest expense mainly due to lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar will 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, there may be the need for additional liquidity in the future. To mitigate this liquidity risk, we expect to maintain $2.0 billion of committed credit facilities, and will continuously monitor our exposures and obligations.

Accounting Estimates

A number of our accounting estimates, including those outlined in in the Critical Accounting Policies and Estimates section of our 2011 Annual MD&A, are based on the current economic environment and outlook. While we do not anticipate significant changes to these estimates 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 2012 is expected to be approximately 20 to 25 per cent.

Capital Expenditures

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

Growth Capital Expenditures

Included in the current year's growth expenditures is $50 million associated with four significant growth capital projects that are currently in progress that will be completed in 2012. A summary of each of these projects is outlined below:

	Total Project		2011[1]	2012		
Project	**Estimated spend**	**Spent to date[2]**	**Actual spend**	**Estimated spend**	**Target completion date**	**Details**
Keephills Unit 1 uprate	25	13	9	10 - 20	Q3 2012	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	26	10	4	10 - 20	Q2 2012	A 23 MW efficiency uprate at our Keephills facility
Sundance Unit 3 uprate	27	11	8	15 - 20	Q4 2012	A 15 MW efficiency uprate at our Sundance facility
New Richmond[3]	205	29	29	165 - 185	Q4 2012	A 68 MW wind farm in Quebec
Total growth	**283**	**63**	**50**	**200 - 245**		

Transmission

For the year ended Dec. 31, 2011, a total of $5 million was spent on transmission projects. The estimated spend for 2012 for transmission projects is $8 million. Transmission projects consist of the major maintenance and reconfiguration of the transmission networks of Alberta to increase capacity of power flow in the lines.

Sustaining Capital Expenditures

A significant portion of our sustaining capital expenditures is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Some of these amounts were previously expensed under Canadian GAAP. Under IFRS, planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event.

(1) In 2011, we also spent a combined total of $73 million on Keephills Unit 3, Bone Creek, Ardenville, and Kent Hills 2. Keephills Unit 3 amounts spent included a non-capital expenditure of $7 million and a coal cost reduction of $2 million. Bone Creek amounts spent as of Dec. 31, 2011 included a non-capital credit of $9 million.

(2) Represents amounts spent as of Dec. 31, 2011.

(3) New Richmond amounts spent as of Dec. 31, 2011 include expenditures of $5 million, which had been previously included in project development costs.

For 2012, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	**Description**	**Spent in 2011**	**Expected spend in 2012**
Routine capital	Expenditures to maintain our existing generating capacity	114	100 - 115
Productivity capital	Projects to improve power production efficiency	42	70 - 90
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	21	40 - 50
Planned maintenance	Regularly scheduled major maintenance	184	290 - 310
Total sustaining expenditures		**361**	**500 - 565**

Details of the 2012 planned maintenance program, including major inspection costs, are outlined as follows:

	Coal	Gas and Renewables	**Expected spend in 2012**
Capitalized	215 - 230	75 - 80	**290 - 310**
Expensed	0 - 0	0 - 5	**0 - 5**
	215 - 230	75 - 85	**290 - 315**

	Coal	Gas and Renewables	**Total**
GWh lost	2,880 - 2,890	420 - 430	**3,300 - 3,320**

Financing

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

NON-IFRS MEASURES

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

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

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	
	2011	2010	**2011**	2010
Revenues	**701**	779	**2,663**	2,673
Fuel and purchased power	**292**	328	**947**	1,185
Gross margin	**409**	451	**1,716**	1,488
Operations, maintenance, and administration	**145**	129	**545**	510
Depreciation and amortization	**133**	117	**482**	464
Taxes, other than income taxes	**6**	6	**27**	27
Operating expenses	**284**	252	**1,054**	1,001
Operating income	**125**	199	**662**	487
Finance lease income	**2**	2	**8**	8
Equity (loss) income	**(2)**	(1)	**14**	7
Gain on sale of assets	**13**	-	**16**	-
Other income	**-**	-	**2**	-
Foreign exchange (loss) gain	**(3)**	4	**(3)**	8
Asset impairment charges	**(3)**	(28)	**(17)**	(28)
Reserve on collateral	**(18)**	-	**(18)**	-
Net interest expense	**(64)**	(48)	**(215)**	(178)
Earnings before income taxes	**50**	128	**449**	304
Income tax expense	**11**	31	**106**	24
Net earnings	**39**	97	**343**	280
Non-controlling interests	**11**	4	**38**	24
Net earnings attributable to TransAlta shareholders	**28**	93	**305**	256
Preferred share dividends	**4**	1	**15**	1
Net earnings attributable to common shareholders	**24**	92	**290**	255

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with results from prior periods. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period. In calculating comparable earnings, we exclude the impact related to certain hedges deemed ineffective for accounting purposes, as these transactions are unusual in nature and have not historically been a normal occurrence in the course of operating our business. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings in the period in which they settle. As these gains have already been recognized in earnings in the current period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

In calculating comparable earnings for 2011, we have also excluded the gain on the sale of facilities and development projects, the writeoff of acquired wind development costs, the writedown of certain capital spares, asset impairment charges, and reserve on collateral, as these items are not considered regular business activities.

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Net earnings attributable to common shareholders	**24**	92	**290**	255
Impacts associated with certain de-designated and ineffective hedges, net of tax	**(1)**	(28)	**(81)**	(28)
Gain on sale of facilities and development projects, net of tax	**(10)**	-	**(12)**	-
Writeoff of wind development costs, net of tax	**1**	-	**4**	-
Writedown of capital spares, net of tax	**-**	-	**3**	-
Asset impairment charges, net of tax	**2**	16	**13**	16
Reserve on collateral, net of tax	**13**	-	**13**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	(30)
Earnings on a comparable basis	**29**	80	**230**	213
Weighted average number of common shares outstanding in the period	**224**	220	**222**	219
Earnings on a comparable basis per share	**0.13**	0.36	**1.04**	0.97

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.

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Operating income	**125**	199	**662**	487
Depreciation and amortization per the Consolidated Statements of Cash Flows(1)	**149**	139	**532**	511
EBITDA	**274**	338	**1,194**	998
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(2)**	(43)	**(127)**	(43)
Writeoff of wind development costs, pre-tax	**1**	-	**6**	-
Writedown of capital spares, pre-tax	**-**	-	**4**	-
Comparable EBITDA	**273**	295	**1,077**	955

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 using the weighted average number of common shares outstanding during the period.

(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.

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Cash flow from operating activities	**182**	317	**694**	838
Change in non-cash operating working capital balances	**7**	(83)	**115**	(33)
Funds from operations	**189**	234	**809**	805
Weighted average number of common shares outstanding in the period	**224**	220	**222**	219
Funds from operations per share	**0.84**	1.06	**3.64**	3.68

Free Cash Flow

Free cash flow represents the amount of cash generated by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments 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 expenditures for the three months ended Dec. 31, 2011 represents total additions to PP&E and intangibles per the Consolidated Statements of Cash Flows less $41 million ($40 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2010, we invested $91 million ($86 million net of joint venture contributions) in growth projects. For the years ended Dec. 31, 2011 and 2010, we invested $125 million ($123 million net of joint venture contributions) and $482 million ($470 million net of joint venture contributions), respectively, in growth projects.

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2011	2010	**2011**	2010
Cash flow from operating activities	**182**	317	**694**	838
Add (deduct):				
Changes in working capital	**7**	(83)	**115**	(33)
Sustaining capital expenditures	**(111)**	(113)	**(361)**	(355)
Dividends paid on common shares	**(48)**	(47)	**(191)**	(216)
Dividends paid on preferred shares	**(4)**	-	**(15)**	-
Distributions paid to subsidiaries' non-controlling interests	**(17)**	(18)	**(61)**	(62)
Free cash flow	**9**	56	**181**	172

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 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**

	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Revenue	696	547	651	779
Net earnings attributable to common shareholders	60	63	40	92
Net earnings per share attributable to common shareholders, basic and diluted	0.27	0.29	0.18	0.42
Comparable earnings per share	0.27	0.15	0.18	0.36

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 further developments, and 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 those 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 their attendant costs; expectations related to future earnings and cash flow from operating activities; estimates of fuel supply and demand conditions and the costs of procuring fuel; our estimated spend on growth and sustaining capital projects; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; 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 impact of certain hedges on future reported earnings; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar; and the monitoring of our exposure to liquidity risk.

Factors that may adversely impact our forward looking statements include risks relating to: fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; 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; 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; 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 2011 Annual MD&A and under the heading "Risk Factors" in our 2012 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

(in millions of Canadian dollars except per share amounts)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2011**	2010	**2011**	2010
Revenues	**701**	779	**2,663**	2,673
Fuel and purchased power	**292**	328	**947**	1,185
	409	451	**1,716**	1,488
Operations, maintenance, and administration	**145**	129	**545**	510
Depreciation and amortization	**133**	117	**482**	464
Taxes, other than income taxes	**6**	6	**27**	27
	284	252	**1,054**	1,001
	125	199	**662**	487
Finance lease income	**2**	2	**8**	8
Equity (loss) income	**(2)**	(1)	**14**	7
Gain on sale of assets	**13**	-	**16**	-
Other income	**-**	-	**2**	-
Foreign exchange (loss) gain	**(3)**	4	**(3)**	8
Asset impairment charges	**(3)**	(28)	**(17)**	(28)
Reserve on collateral	**(18)**	-	**(18)**	-
Net interest expense	**(64)**	(48)	**(215)**	(178)
Earnings before income taxes	**50**	128	**449**	304
Income tax expense	**11**	31	**106**	24
Net earnings	**39**	97	**343**	280
Net earnings attributable to:				
TransAlta shareholders	**28**	93	**305**	256
Non-controlling interests	**11**	4	**38**	24
	39	97	**343**	280
Net earnings attributable to TransAlta shareholders	**28**	93	**305**	256
Preferred share dividends	**4**	1	**15**	1
Net earnings attributable to common shareholders	**24**	92	**290**	255
Weighted average number of common shares outstanding in the year *(millions)*	**224**	220	**222**	219
Net earnings per share attributable to common shareholders, basic and diluted	**0.11**	0.42	**1.31**	1.16

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(in millions of Canadian dollars)

Unaudited	3 months ended Dec. 31 **2011**	2010	Year ended Dec. 31 **2011**	2010
Net earnings	**39**	97	**343**	280
Other comprehensive (loss) income				
(Losses) gains on translating net assets of foreign operations	**(11)**	(35)	**32**	(57)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(1)	**9**	23	**(33)**	33
Reclassification of gains on translation of foreign operations to net earnings, net of tax(2)	**-**	(3)	**-**	(3)
(Losses) gains on derivatives designated as cash flow hedges, net of tax(3)	**(65)**	(77)	**(103)**	147
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(4)	**-**	-	**-**	8
Reclassification of losses (gains) on derivatives designated as cash flow hedges to net earnings, net of tax(5)	**26**	(46)	**(177)**	(129)
Net actuarial (losses) gains on defined benefit plans, net of tax(6)	**(7)**	13	**(26)**	(20)
Other comprehensive loss	**(48)**	(125)	**(307)**	(21)
Comprehensive (loss) income	**(9)**	(28)	**36**	259

	3 months ended Dec. 31 **2011**	2010	Year ended Dec. 31 **2011**	2010
Total comprehensive (loss) income attributable to:				
Common shareholders	**(4)**	(30)	**18**	252
Non-controlling interests	**(5)**	2	**18**	7
	(9)	(28)	**36**	259

(1) Net of income tax expense of 1 and 5 recovery for the three and twelve months ended Dec. 31, 2011 (2010 - 4 expense and 6 expense), respectively.

(2) Net of income tax expense of nil for the three and twelve months ended Dec. 31, 2011 (2010 - nil), respectively.

(3) Net of income tax recovery of 11 and 7 for the three and twelve months ended Dec. 31, 2011 (2010 - 37 recovery and 87 expense), respectively.

(4) Net of income tax expense of nil for the three and twelve months ended Dec. 31, 2011 (2010 - nil and 3 recovery), respectively.

(5) Net of income tax recovery of 5 and 94 expense for the three and twelve months ended Dec. 31, 2011 (2010 - 22 expense and 65 expense), respectively.

(6) Net of income tax recovery of 2 and 9 for the three and twelve months ended Dec. 31, 2011 (2010 - 4 expense and 7 recovery), respectively.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Cash and cash equivalents	**49**	35	53
Accounts receivable	**541**	412	405
Current portion of finance lease receivable	**3**	2	2
Collateral paid	**45**	27	27
Prepaid expenses	**8**	10	18
Risk management assets	**391**	268	146
Income taxes receivable	**2**	18	38
Inventory	**85**	53	90
Assets held for sale	**-**	60	4
	1,124	885	783
Investments	**193**	190	202
Long-term receivable	**18**	-	49
Finance lease receivable	**42**	46	48
Property, plant, and equipment			
Cost	**11,420**	11,040	10,831
Accumulated depreciation	**(4,132)**	(3,746)	(3,754)
	7,288	7,294	7,077
Goodwill	**447**	447	447
Intangible assets	**283**	288	293
Deferred income tax assets	**176**	178	229
Risk management assets	**99**	205	222
Other assets	**90**	102	103
Total assets	**9,760**	9,635	9,453
Accounts payable and accrued liabilities	**463**	482	484
Decommissioning and other provisions	**99**	54	61
Collateral received	**16**	126	86
Risk management liabilities	**208**	35	45
Income taxes payable	**22**	8	9
Dividends payable	**67**	130	61
Current portion of long-term debt	**316**	237	9
Liabilities held for sale	**-**	3	-
	1,191	1,075	755
Long-term debt	**3,721**	3,823	4,231
Decommissioning and other provisions	**283**	256	287
Deferred income tax liabilities	**491**	538	542
Risk management liabilities	**142**	123	78
Deferred credits and other long-term liabilities	**305**	269	236
Equity			
Common shares	**2,273**	2,204	2,164
Preferred shares	**562**	293	-
Contributed surplus	**9**	7	5
Retained earnings	**527**	431	495
Accumulated other comprehensive (loss) income	**(102)**	185	189
Equity attributable to shareholders	**3,269**	3,120	2,853
Non-controlling interests	**358**	431	471
Total equity	**3,627**	3,551	3,324
Total liabilities and equity	**9,760**	9,635	9,453

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

Unaudited	Common shares	Preferred shares	Contributed surplus	Retained earnings	Year ended Dec. 31, 2011 Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Jan. 1, 2010	2,164	-	5	495	189	2,853	471	3,324
Net earnings	-	-	-	256	-	256	24	280
Other comprehensive income (loss):								
Losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(27)	(27)	-	(27)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	43	43	(17)	26
Net actuarial losses on defined benefit plans, net of tax	-	-	-	-	(20)	(20)	-	(20)
Total comprehensive (loss) income					(4)	252	7	259
Common share dividends	-	-	-	(319)	-	(319)	-	(319)
Preferred share dividends	-	-	-	(1)	-	(1)	-	(1)
Distributions to non-controlling interests	-	-	-	-	-	-	(62)	(62)
Common shares issued	40	-	-	-	-	40	-	40
Preferred shares issued	-	293	-	-	-	293	-	293
Effect of share-based payment plans	-	-	2	-	-	2	-	2
Sale of minority interest in Kent Hills	-	-	-	-	-	-	15	15
Balance, Dec. 31, 2010	2,204	293	7	431	185	3,120	431	3,551
Net earnings	-	-	-	305	-	305	38	**343**
Other comprehensive loss:								
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 benefit plans, net of tax	-	-	-	-	(26)	(26)	-	**(26)**
Total comprehensive (loss) income					(287)	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**

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2011**	2010	**2011**	2010
Operating activities				
Net earnings	**39**	97	**343**	280
Depreciation and amortization	**149**	139	**532**	511
Gain on sale of assets	**(13)**	-	**(16)**	-
Accretion of provisions	**4**	5	**19**	18
Decommissioning and restoration costs settled	**(10)**	(10)	**(33)**	(37)
Deferred income taxes	**1**	26	**80**	54
Unrealized gain from risk management activities	**(15)**	(49)	**(175)**	(47)
Unrealized foreign exchange loss (gain)	**11**	(3)	**3**	(3)
Provisions	**-**	-	**22**	-
Asset impairment charges	**3**	28	**17**	28
Reserve on collateral	**18**	-	**18**	-
Equity income, net of distributions received	**17**	10	**1**	2
Other non-cash items	**(15)**	(9)	**(2)**	(1)
	189	234	**809**	805
Change in non-cash operating working capital balances	**(7)**	83	**(115)**	33
Cash flow from operating activities	**182**	317	**694**	838
Investing activities				
Additions to property, plant, and equipment	**(135)**	(193)	**(453)**	(808)
Additions to intangibles	**(14)**	(12)	**(30)**	(29)
Proceeds on sale of property, plant, and equipment	**9**	3	**12**	6
Proceeds on sale of facilities and development projects	**10**	-	**40**	-
Proceeds on sale of minority interest in Kent Hills	**-**	15	**-**	15
Acquisition of the remaining 50% of the Taylor Hydro joint venture	**(7)**	-	**(7)**	-
Resolution of certain tax matters	**-**	17	**3**	29
Realized losses on financial instruments	**(7)**	(7)	**(12)**	(29)
Net (decrease) increase in collateral received from counterparties	**(13)**	(39)	**(109)**	47
Net (increase) decrease in collateral paid to counterparties	**(48)**	4	**(56)**	(2)
Other	**1**	(1)	**(3)**	6
Cash flow used in investing activities	**(204)**	(213)	**(615)**	(765)
Financing activities				
Net (decrease) increase in borrowings under credit facilities	**(200)**	(356)	**155**	(400)
Repayment of long-term debt	**(2)**	(3)	**(234)**	(10)
Issuance of long-term debt	**-**	-	**-**	301
Dividends paid on common shares	**(48)**	(47)	**(191)**	(216)
Dividends paid on preferred shares	**(4)**	-	**(15)**	-
Net proceeds on issuance of common shares	**1**	-	**2**	1
Net proceeds on issuance of preferred shares	**267**	291	**267**	291
Realized gains on financial instruments	**4**	11	**9**	3
Distributions paid to subsidiaries' non-controlling interests	**(17)**	(18)	**(61)**	(62)
Decrease in finance lease receivable	**1**	-	**3**	2
Other	**2**	-	**(2)**	-
Cash flow from (used in) financing activities	**4**	(122)	**(67)**	(90)
Cash flow (used in) from operating, investing, and financing activities	**(18)**	(18)	**12**	(17)
Effective change in value of foreign cash	**1**	(4)	**2**	(1)
(Decrease) increase in cash and cash equivalents	**(17)**	(22)	**14**	(18)
Cash and cash equivalents, beginning of year	**66**	57	**35**	53
Cash and cash equivalents, end of year	**49**	35	**49**	35
Cash income taxes paid (recovered)	5	(28)	**(1)**	**(51)**
Cash interest paid	70	15	**197**	**142**

FIRST-TIME ADOPTION OF IFRS

IFRS 1 *First-time Adoption of International Financial Reporting Standards* provides specific requirements for an entity's initial adoption of IFRS.

IFRS 1 requires that an entity's accounting policies used in its opening statement of financial position and throughout all periods presented in its first IFRS financial statements comply with IFRS effective at the end of its first IFRS reporting period. Accordingly, the IFRS currently issued and effective as of Dec. 31, 2011, have been applied in preparing the consolidated financial statements as at and for the years ended Dec. 31, 2011 and 2010 and in preparing the opening IFRS Statement of Financial Position as at Jan. 1, 2010.

In certain circumstances, IFRS 1 provides for exceptions to, or exemptions from, retrospective application of certain IFRS. The following IFRS 1 exemptions and elections have been utilized by the Corporation:

- The cumulative net foreign exchange losses related to the translation of foreign operations, net of foreign exchange amounts on related net investment hedges, has been reset to zero at Jan. 1, 2010.
- We have determined whether arrangements existing at the date of transition to IFRS contain, or are considered to be, a lease on the basis of facts and circumstances existing at that date. Where the same determination as required by IFRS was made at a different date in accordance with our previous GAAP, arrangements reviewed under our previous GAAP have not been reassessed for IFRS transition. We are required to review arrangements outside of the scope of our previous GAAP and have determined that one of the agreements contains a finance lease.
- International Financial Reporting Standards Interpretations Committee 1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* ("IFRIC 1") has not been applied retrospectively to determine the cost of decommissioning assets. The simplified method permitted under IFRS 1 has been applied.
- IFRS 2 *Share-based Payment* has been applied to equity instruments that were granted on or after Nov. 7, 2002 but that had not vested by our transition date of Jan. 1, 2010.
- IFRS 3 *Business Combinations* has not been applied retrospectively to business combinations occurring prior to the date of transition to IFRS. Accordingly, assets and liabilities acquired in business combinations prior to Jan. 1, 2010 continue to be measured and recorded at the carrying amounts determined under our previous GAAP.
- Our Australian subsidiaries adopted IFRS effective Jan. 1, 2005. Where IFRS adopted by the Corporation may have permitted re-measurements of the Australian subsidiaries' assets and liabilities, we have elected not to do so.
- International Accounting Standard 23 *Borrowing Costs* ("IAS 23") has been applied prospectively to borrowing costs relating to qualifying assets for which the commencement date for capitalization is on or after the transition date.
- Amounts capitalized under our previous GAAP, such as allowance for funds used during construction and general overheads for certain PP&E assets that were operated in rate-regulated environments, have not been restated to comply with cost as determined by IAS 16 *Property, Plant and Equipment.* The carrying amount of these items under our previous GAAP was determined following prescribed regulations and has been elected as deemed cost.
- We have elected to recognize, at the date of transition, all cumulative actuarial gains and losses associated with our defined benefit pension and other post-employment benefit plans.
- Certain IAS 19 *Employee Benefits* disclosures have been applied prospectively from the date of transition to IFRS.

Differences between our previous GAAP and our IFRS financial position as at Jan. 1, 2010 and as at Dec. 31, 2010, our financial performance for the year ended Dec. 31, 2010, and our cash flows for the year ended Dec. 31, 2010, are outlined in the following tables and explanatory notes:

Reconciliation of Financial Position as at Jan. 1, 2010

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(in millions of Canadian dollars)

As at Jan. 1, 2010	Canadian GAAP	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31	IAS 37	IFRIC 4/ IAS 17	IAS 36	Reclass	IFRS
Cash and cash equivalents	82	-	-	-	-	(29)	-	-	-	-	**53**
Accounts receivable	421	-	-	-	-	(16)	-	-	-	-	**405**
Current portion of finance lease receivable	-	-	-	-	-	-	-	2	-	-	**2**
Collateral paid	27	-	-	-	-	-	-	-	-	-	**27**
Prepaid expenses	18	-	-	-	-	-	-	-	-	-	**18**
Risk management assets	144	-	-	-	-	-	-	-	-	2	**146**
Income taxes receivable	39	-	-	-	-	(1)	-	-	-	-	**38**
Inventory	90	-	-	-	-	-	-	-	-	-	**90**
Assets held for sale	-	-	-	-	-	-	-	-	-	4	**4**
	821	-	-	-	-	(46)	-	2	-	6	**783**
Investments	-	-	-	-	-	202	-	-	-	-	**202**
Long-term receivables	49	-	-	-	-	-	-	-	-	-	**49**
Finance lease receivable	-	-	-	-	-	-	-	48	-	-	**48**
Property, plant, and equipment											
Cost	11,701	-	(104)	200	-	(366)	(22)	(55)	(283)	(240)	**10,831**
Accumulated depreciation	(4,142)	-	1	(85)	-	103	20	25	196	128	**(3,754)**
	7,559	-	(103)	115	-	(263)	(2)	(30)	(87)	(112)	**7,077**
Goodwill	434	-	87	-	-	(74)	-	-	-	-	**447**
Intangible assets	344	-	(10)	-	-	(149)	-	-	-	108	**293**
Deferred income tax assets	234	-	-	(3)	7	-	4	-	22	(35)	**229**
Risk management assets	224	-	-	-	-	-	-	-	-	(2)	**222**
Other assets	121	-	-	-	(18)	-	-	-	-	-	**103**
Total assets	9,786	-	(26)	112	(11)	(330)	2	20	(65)	(35)	**9,453**
Accounts payable and accrued liabilities	521	-	2	-	-	(12)	-	-	2	(29)	**484**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	-	61	**61**
Collateral received	86	-	-	-	-	-	-	-	-	-	**86**
Risk management liabilities	45	-	-	-	-	-	-	-	-	-	**45**
Income taxes payable	10	-	-	-	-	(1)	-	-	-	-	**9**
Future income tax liabilities	45	-	-	-	-	-	-	-	-	(45)	**-**
Dividends payable	61	-	-	-	-	-	-	-	-	-	**61**
Current portion of long-term debt	31	-	-	-	-	(22)	-	-	-	-	**9**
Current portion of asset retirement obligations	32	-	-	-	-	-	-	-	-	(32)	**-**
	831	-	2	-	-	(35)	-	-	2	(45)	**755**
Long-term debt	4,411	-	-	-	-	(180)	-	-	-	-	**4,231**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	-	287	**287**
Deferred income tax liabilities	662	-	(29)	26	(22)	(95)	(6)	3	(7)	10	**542**
Risk management liabilities	78	-	-	-	-	-	-	-	-	-	**78**
Deferred credits and other long-term liabilities	147	-	-	-	89	-	-	-	8	(8)	**236**
Asset retirement obligations	250	-	-	-	-	(5)	34	-	-	(279)	**-**
Non-controlling interests	478	-	-	2	-	(16)	-	10	(3)	(471)	**-**
Equity											
Common shares	2,164	-	-	-	-	-	-	-	-	-	**2,164**
Contributed surplus	5	-	-	-	-	-	-	-	-	-	**5**
Retained earnings	634	(63)	1	84	(78)	1	(26)	7	(65)	-	**495**
Accumulated other comprehensive income	126	63	-	-	-	-	-	-	-	-	**189**
Equity attributable to shareholders	2,929	-	1	84	(78)	1	(26)	7	(65)	-	**2,853**
Non-controlling interests	-	-	-	-	-	-	-	-	-	471	**471**
Total equity	2,929	-	1	84	(78)	1	(26)	7	(65)	471	**3,324**
Total liabilities and equity	9,786	-	(26)	112	(11)	(330)	2	20	(65)	(35)	**9,453**

Reconciliation of Financial Position as at Dec. 31, 2010

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(in millions of Canadian dollars)

As at Dec. 31, 2010	Canadian GAAP	IAS 21	IAS 16	IAS 19	IAS 31	IAS 37	IFRIC 4/ IAS 17	IAS 36	Reclass	IFRS
Cash and cash equivalents	58	-	-	-	(23)	-	-	-	-	**35**
Accounts receivable	428	-	-	-	(16)	-	-	-	-	**412**
Current portion of finance lease receivable	-	-	-	-	-	-	2	-	-	**2**
Collateral paid	27	-	-	-	-	-	-	-	-	**27**
Prepaid expenses	10	-	-	-	-	-	-	-	-	**10**
Risk management assets	265	-	-	-	-	-	-	-	3	**268**
Income taxes receivable	19	-	-	-	(1)	-	-	-	-	**18**
Inventory	53	-	-	-	-	-	-	-	-	**53**
Assets held for sale	-	-	-	-	-	-	-	-	60	**60**
	860		-	-	(40)	-	2	-	63	**885**
Investments	-	-	-	-	190	-	-	-	-	**190**
Finance lease receivable	-	-	-	-	-	-	46	-	-	**46**
Property, plant, and equipment										
Cost	11,706	-	208	-	(365)	26	(55)	(219)	(261)	**11,040**
Accumulated depreciation	(4,129)	-	(108)	-	129	(12)	28	196	150	**(3,746)**
	7,577	-	100	-	(236)	14	(27)	(23)	(111)	**7,294**
Assets held for sale	60	-	-	-	-	-	-	-	(60)	**-**
Goodwill	517	-	-	-	(70)	-	-	-	-	**447**
Intangible assets	304	-	-	-	(127)	-	-	-	111	**288**
Deferred income tax assets	240	-	(3)	6	-	2	-	-	(67)	**178**
Risk management assets	208	-	-	-	-	-	-	-	(3)	**205**
Other assets	127	-	-	(25)	-	-	-	-	-	**102**
Total assets	9,893	-	97	(19)	(283)	16	21	(23)	(67)	**9,635**
Short-term debt	1	-	-	-	(1)	-	-	-	-	**-**
Accounts payable and accrued liabilities	503	-	-	-	(7)	-	-	1	(15)	**482**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	54	**54**
Collateral received	126	-	-	-	-	-	-	-	-	**126**
Risk management liabilities	35	-	-	-	-	-	-	-	-	**35**
Income taxes payable	8	-	-	-	-	-	-	-	-	**8**
Future income tax liabilities	77	-	-	-	-	-	-	-	(77)	**-**
Dividends payable	130	-	-	-	-	-	-	-	-	**130**
Current portion of long-term debt	255	-	-	-	(18)	-	-	-	-	**237**
Current portion of asset retirement obligations	38	-	-	-	-	-	-	-	(38)	**-**
Liabilities held for sale	-	-	-	-	-	-	-	-	3	**3**
	1,173	-	-	-	(26)	-	-	1	(73)	**1,075**
Long-term debt	3,979	-	-	-	(156)	-	-	-	-	**3,823**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	256	**256**
Deferred income tax liabilities	630	-	22	(30)	(84)	(7)	3	(6)	10	**538**
Risk management liabilities	123	-	-	-	-	-	-	-	-	**123**
Deferred credits and other long-term liabilities	169	-	-	110	-	-	-	(1)	(9)	**269**
Liabilities held for sale	3	-	-	-	-	-	-	-	(3)	**-**
Asset retirement obligations	204	-	-	-	(5)	48	-	-	(247)	**-**
Non-controlling interests	435	-	2	-	(16)	-	11	-	(432)	**-**
Equity										
Common shares	2,204	-	-	-	-	-	-	-	-	**2,204**
Preferred shares	293	-	-	-	-	-	-	-	-	**293**
Contributed surplus	7	-	-	-	-	-	-	-	-	**7**
Retained earnings	533	(62)	73	(80)	4	(25)	7	(19)	-	**431**
Accumulated other comprehensive income	140	62	-	(19)	-	-	-	2	-	**185**
Equity attributable to shareholders	3,177	-	73	(99)	4	(25)	7	(17)	-	**3,120**
Non-controlling interests	-	-	-	-	-	-	-	-	431	**431**
Total equity	3,177	-	73	(99)	4	(25)	7	(17)	431	**3,551**
Total liabilities and equity	9,893	-	97	(19)	(283)	16	21	(23)	(67)	**9,635**

Explanations of the adjustments from our previous GAAP to IFRS related to the Consolidated Statements of Financial Position as at Jan.1, 2010 and Dec. 31, 2010 in the above-noted tables are as follows:

IAS 21 *The Effects of Changes in Foreign Exchange Rates*

Retrospective application of IAS 21 would require identification of the foreign exchange gains or losses for each foreign operation and recalculation of these gains or losses on each foreign operation's IFRS transition adjustments. IFRS 1 provides that a first-time adopter need not comply with these IAS 21 requirements. Accordingly, the cumulative net foreign exchange losses for all foreign operations, including the foreign exchange amounts arising on related net investment hedges, net of tax, has been reset to zero on transition. Net gains or losses arising subsequent to transition are recognized in Other Comprehensive Income ("OCI") in accordance with our accounting policy. Please refer to *Note 2* of our audited consolidated financial statements within our 2011 Annual Report for an outline of our accounting policy.

IFRS 3 *Business Combinations*

IFRS 3 requires that when the initial accounting for a business combination is incomplete and adjustments are subsequently made to the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date, the adjustments are made retrospectively. Our previous GAAP required prospective application of the adjustments from the date the adjustments were determined. Accordingly, the adjustments on transition relate to the retrospective application of the Corporation's final allocation of the Canadian Hydro consideration transferred.

IAS 16 *Property, Plant and Equipment*

IAS 16 requires the capitalization of costs associated with planned major maintenance and inspection activities. Planned major maintenance includes inspection, repair and maintenance of existing components, and the replacement of existing components. Some of these amounts were expensed under our previous GAAP. On transition, the unamortized amount of previously expensed planned major maintenance and inspection costs has been capitalized as part of PP&E. Costs incurred subsequently for planned major maintenance activities are capitalized in the period maintenance activities occur and amortized on a straight-line basis over the term until the next major maintenance event.

IAS 19 *Employee Benefits*

Under our previous GAAP, the corridor approach was used to account for actuarial gains and losses on defined benefit pension and other post-employment benefit plans. Under the corridor approach, some actuarial gains and losses remained unrecognized. Application of the corridor approach under IAS 19 would require the cumulative actuarial gains and losses from inception of each plan to the transition date to be split into recognized and unrecognized amounts. IFRS 1 permits recognition of all cumulative actuarial gains and losses at the date of transition to IFRS, even if the corridor approach is not used thereafter. Actuarial gains and losses arising subsequent to the transition date are recognized in OCI. Please refer to *Note 2* of our audited consolidated financial statements within our 2011 Annual Report for an outline of our accounting policy.

IAS 31 *Interests in Joint Ventures*

Under our previous GAAP, all joint ventures were accounted for using the proportionate consolidation method. Under IFRS, parties to a joint venture recognize their contractual rights and obligations arising from the venture. Joint ventures are classified into three types: jointly controlled assets, jointly controlled operations, and jointly controlled entities. Our joint ventures are classified as jointly controlled assets or jointly controlled entities under IFRS.

For jointly controlled assets, the accounting requirements under IFRS generally result in the same accounting as proportionate consolidation under our previous GAAP. Under IFRS, a venturer can choose to recognize its interest in a jointly controlled entity using either proportionate consolidation or the equity method. We account for our interest in jointly controlled entities using the equity method. Under the equity method, our investments in the CE Gen and Wailuku jointly controlled entities are reflected as a single line item, entitled "Investments", on the Consolidated Statements of Financial Position, and our share of the income is reflected as equity earnings or loss in the Consolidated Statements of Earnings. Our share of the cash and cash equivalents, and the cash flow changes, of these equity accounted investments are no longer presented within each line item of the operating, investing, or financing activities in the Consolidated Statements of Cash Flows. Instead, cash distributions received are presented as an operating activity and cash returns of invested capital, or cash invested, are presented as an investing activity.

IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*

IAS 37 requires provisions to be measured at the present value of the amounts expected to be paid where the effect of the time value of money is material. Provisions must be reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including consideration of the effects of changes in the market-based, risk-adjusted discount rate, where applicable. Our previous GAAP did not require consideration of changes in the market-based, risk-adjusted discount rate at each period end. Our provisions for decommissioning and restoration, and other provisions, have been measured at transition and at subsequent period ends using a current market-based interest rate at those dates, adjusted for the risks specific to the liabilities.

Under IFRIC 1, the amount of a change in a decommissioning and restoration liability resulting from i) changes in the estimated timing or amount of cash flows and ii) changes in the current market-based, risk-adjusted discount rate, must be added to, or deducted from, the cost of the related asset.

Retrospective application of IAS 37 and IFRIC 1 would have required us to reconstruct a historical record of all such adjustments that would have been made in the past. Use of the IFRS 1 exemption permits the amount included in the cost of the related asset to be estimated by discounting the liability back to the date when the liability first arose using management's best estimate of the average historical risk-adjusted discount rates that would have applied over the intervening period. Accumulated depreciation on this asset amount has been calculated on the basis of the current estimate of the useful life of the asset. Please refer to *Note 2* of our audited consolidated financial statements within our 2011 Annual Report for an outline of the IFRS depreciation policies.

IAS 17 *Leases* / IFRIC 4 *Determining whether an Arrangement contains a Lease*

Under IAS 17, a lease is defined as an agreement whereby the lessor conveys to the lessee, in return for a payment, or a series of payments, the right to use a specific asset for an agreed period of time. IFRIC 4 provides guidance on how to determine whether an arrangement that is not structured as a lease contains, or is considered to be, a lease as defined in IAS 17. As a result of the specific terms and conditions of our Fort Saskatchewan long-term contract, it has been determined to be a finance lease. Certain other PPAs and long-term contracts have been determined to be, or contain, operating leases.

Finance Leases

Where we determine that the contractual provisions of the PPA or other long-term contract have resulted in the customer assuming the principal risks and rewards of ownership of the plant, the arrangement is a finance lease. The assets subject to the lease have been removed from our PP&E and the amounts due from the lessees under the related finance leases recorded in the Consolidated Statements of Financial Position as financial assets, classified as finance lease receivables. The payments considered to be part of the leasing arrangement are apportioned between the finance lease receivable and finance income.

Operating Leases

Where we determine that the contractual provisions of the PPA or other long-term contract have resulted in the Corporation retaining the principal risks and rewards of ownership of the plant, the arrangement is an operating lease. The assets subject to the lease continue to be recorded as PP&E and depreciated over their useful lives.

PPAs and other long-term contracts that are not considered to be, or contain, leases, result in the continued recognition of PP&E and revenues, consistent with our previous GAAP.

IAS 36 *Impairment of Assets*

Under IAS 36, undiscounted future cash flows are not used to initially assess for impairment, as under our previous GAAP. Instead, when an indication of impairment exists, the asset's carrying amount is compared to the greater of its value in use or fair value less normal costs to sell. As a result, on transition, we recognized pre-tax impairment losses of $101 million ($98 million after deducting the amount that was attributed to the non-controlling interest) that were comprised of $70 million related to the natural gas fleet and $31 million related to the coal fleet. The natural gas fleet impairment results from lower forecast pricing at one of the merchant facilities and the sale of one of our contracted facilities. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and is primarily due to our shift in managing the coal-fired generation facilities on a unit pair basis and the shut down due to the physical state of the boilers such that the units cannot be economically restored to service under the terms of the PPA. The recoverable amounts of impaired assets were based on fair value derived through the use of discounted cash flow analysis from our long-range forecasts and other market-based assumptions, as considered appropriate. Due to IFRS transition impairments, the timing of recognition of impairment losses in 2010 differed under IFRS versus our previous GAAP.

IFRS Reclassifications

- Under IFRS, mineral rights and reserves and software are accounted for pursuant to IAS 38 *Intangible Assets*, whereas under our previous GAAP, they were classified as PP&E.
- Under IAS 12 *Income Taxes*, future income taxes are referred to as deferred income tax assets and liabilities, which must be classified as non-current, whereas our previous GAAP permitted both current and non-current classification.
- Under IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations*, non-current assets meeting the definition of held for sale are classified as current assets, whereas our previous GAAP permitted non-current classification.
- Under IAS 37, we have classified our provisions for decommissioning and restoration activities together with all other provisions, whereas under our previous GAAP such provisions were reflected as a separate line item on the Consolidated Statements of Financial Position.
- Under IAS 1, non-controlling interests are classified as part of Equity.

Reconciliation of Earnings for the three months and year ended Dec. 31, 2010

CONSOLIDATED STATEMENT OF EARNINGS

(in millions of Canadian dollars)

For the 3 months ended Dec. 31, 2010	Canadian GAAP [(1)]	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31 [(2)]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Revenues	811	-	-	-	-	(30)	-	(2)	-	**779**
Fuel and purchased power	331	-	-	-	-	(2)	(1)	-	-	**328**
	480	-	-	-	-	(28)	1	(2)	-	**451**
Operations, maintenance, and administration	153	-	-	(10)	(1)	(13)	-	-	-	**129**
Depreciation and amortization	111	-	4	22	-	(12)	(5)	(1)	(2)	**117**
Taxes, other than income taxes	6	-	-	-	-	-	-	-	-	**6**
	270	-	4	12	(1)	(25)	(5)	(1)	(2)	**252**
	210	-	(4)	(12)	1	(3)	6	(1)	2	**199**
Finance lease income	-	-	-	-	-	-	-	(6)	8	**2**
Equity income	-	-	-	-	-	(1)	-	-	-	**(1)**
Foreign exchange gain (loss)	6	(2)	-	-	-	-	-	-	-	**4**
Asset impairment charges	(89)	-	-	-	-	-	-	-	61	**(28)**
Net interest expense	(48)	-	-	-	-	4	(4)	-	-	**(48)**
Earnings (loss) before income taxes	79	(2)	(4)	(12)	1	-	2	(7)	71	**128**
Income tax expense (recovery)	16	(3)	(1)	(3)	1	-	1	-	20	**31**
Net earnings (loss)	63	1	(3)	(9)	-	-	1	(7)	51	**97**

(1) Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

(2) Includes impacts of other IFRS adjustment for IAS 16 and IAS 37.

CONSOLIDATED STATEMENT OF EARNINGS

(in millions of Canadian dollars)

For the year ended Dec. 31, 2010	Canadian GAAP [(1)]	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31 [(2)]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Revenues	2,819	-	-	-	-	(136)	-	(10)	-	**2,673**
Fuel and purchased power	1,202	-	-	-	-	(11)	(3)	-	(3)	**1,185**
	1,617	-	-	-	-	(125)	3	(10)	3	**1,488**
Operations, maintenance, and administration	634	-	-	(67)	2	(59)	-	-	-	**510**
Depreciation and amortization	459	-	1	81	-	(49)	(16)	(3)	(9)	**464**
Taxes, other than income taxes	27	-	-	-	-	-	-	-	-	**27**
	1,120	-	1	14	2	(108)	(16)	(3)	(9)	**1,001**
	497	-	(1)	(14)	(2)	(17)	19	(7)	12	**487**
Finance lease income	-	-	-	-	-	-	-	8	-	**8**
Equity income	-	-	-	-	-	7	-	-	-	**7**
Foreign exchange gain (loss)	10	(2)	-	-	-	-	-	-	-	**8**
Asset impairment charges	(89)	-	-	-	-	-	-	-	61	**(28)**
Net interest expense	(178)	-	-	-	-	17	(17)	-	-	**(178)**
Earnings (loss) before non-controlling interests and income taxes	240	(2)	(1)	(14)	(2)	7	2	1	73	**304**
Income tax expense (recovery)	1	(3)	-	(3)	-	4	1	-	24	**24**
Net earnings (loss)	239	1	(1)	(11)	(2)	3	1	1	49	**280**

(1) Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

(2) Includes impacts of other IFRS adjustment for IAS 16 and IAS 37.

Explanations of the adjustments from our previous GAAP to IFRS related to the Consolidated Statements of Earnings for the three months and year ended Dec. 31, 2010 are as follows:

IAS 21 *The Effects of Changes in Foreign Exchange Rates*

On transition to IFRS, the cumulative net foreign exchange losses related to the translation of foreign operations was reset to nil. As a result, the amount reclassified from AOCI to net earnings in 2010 under IFRS due to the wind-up of a foreign subsidiary differed from our previous GAAP.

IFRS 3 *Business Combinations*

IFRS 3 requires subsequent adjustments to the provisional allocation of consideration transferred recognized at the acquisition date to be reflected retrospectively as at the acquisition date, whereas our previous GAAP requires prospective application. As a result, depreciation and amortization recognized in 2010 under our previous GAAP was recognized as a transition date adjustment under IFRS.

IAS 16 *Property, Plant and Equipment*

IAS 16 requires the capitalization of costs associated with planned major maintenance and inspection activities. Some of these amounts were expensed under our previous GAAP. The adjustment represents the capitalization of expenditures incurred in the period that were expensed under our previous GAAP and the depreciation of expenditures capitalized on transition to IFRS.

IAS 19 *Employee Benefits*

As a result of the recognition of unrealized net actuarial losses on transition to IFRS, pension and other post-employment expenses under IFRS differ from our previous GAAP amounts.

IAS 31 *Interests in Joint Ventures*

Under our previous GAAP, joint ventures were accounted for using the proportionate consolidation method. IAS 31 permits the use of the proportionate consolidation method or the equity method for joint ventures classified as jointly controlled entities. We have adopted the equity method for our interests in the CE Gen and Wailuku jointly controlled entities. The adjustment represents the reclassification of our proportionate share of CE Gen's and Wailuku's revenue and expenses from each respective line item to a single line item entitled "Equity income (loss)".

IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*

Amounts expensed as accretion of provisions under IFRS differ compared to accretion under our previous GAAP as IFRS requires provisions to be revalued at the end of each reporting period using a current market-based, risk-adjusted discount rate. In addition, accretion expense is recognized as a finance cost under IFRS and is included in net interest expense, whereas under our previous GAAP, accretion expense was recognized in fuel and purchased power or depreciation and amortization.

IAS 17 *Leases* / IFRIC 4 *Determining whether an Arrangement contains a Lease*

Under IFRS, our Fort Saskatchewan long-term contract is considered a finance lease arrangement. The adjustment represents the reversal of i) revenues recognized under our previous GAAP for the delivery of goods and services and; ii) depreciation on the assets subject to the finance lease; and the recognition of finance lease income earned under the finance lease arrangement.

IAS 36 *Impairment of Assets*

Due to the recognition of asset impairment losses on transition to IFRS, depreciation during 2010 under IFRS was lower than under our previous GAAP. In addition, transportation expenses included in fuel and purchased power were lower in 2010 under IFRS due to the recognition at transition of an onerous contract associated with one of the impaired assets.

Reconciliation of Total Comprehensive Income (Loss) for the three months and year ended Dec. 31, 2010

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

For the 3 months ended Dec. 31, 2010	Canadian GAAP (1)	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31 (2)	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Net earnings (loss)	63	1	(3)	(9)	-	-	1	1	43	**97**
Other comprehensive (loss) income										
(Losses) gains on translating net assets of foreign operations	(38)	-	-	-	1	-	-	-	2	**(35)**
Gains on financial instruments designated as hedges of foreign operations, net of tax	23	-	-	-	-	-	-	-	-	**23**
Reclassification of gains on translation of foreign operations to net earnings, net of tax	(2)	(1)	-	-	-	-	-	-	-	**(3)**
Losses on derivatives designated as cash flow hedges, net of tax	(77)	-	-	-	-	-	-	-	-	**(77)**
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax	(46)	-	-	-	-	-	-	-	-	**(46)**
Net actuarial losses on defined benefit plans, net of tax	-	-	-	-	13	-	-	-	-	**13**
Other comprehensive (loss) income	(140)	(1)	-	-	14	-	-	-	2	**(125)**
Total comprehensive (loss) income	(77)	-	(3)	(9)	14	-	1	1	45	**(28)**
Total comprehensive (loss) income attributable to:										
Common shareholders	(75)	-	(3)	(9)	14	-	1	-	42	(30)
Non-controlling interests	(2)	-	-	-	-	-	-	1	3	2
	(77)	-	(3)	(9)	14	-	1	1	45	**(28)**

(1) Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

(2) Includes impacts of other IFRS adjustment for IAS 16 and IAS 37 .

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

For the year ended Dec. 31, 2010	Canadian GAAP [1]	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31 [2]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Net earnings (loss)	239	1	(1)	(11)	(2)	3	1	1	49	**280**
Other comprehensive (loss) income										
(Losses) gains on translating net assets of foreign operations	(60)	-	-	-	1	-	-	-	2	**(57)**
Gains on financial instruments designated as hedges of foreign operations, net of tax	33	-	-	-	-	-	-	-	-	**33**
Reclassification of gains on translation of foreign operations to net earnings, net of tax	(2)	(1)	-	-	-	-	-	-	-	**(3)**
Gains on derivatives designated as cash flow hedges, net of tax	147	-	-	-	-	-	-	-	-	**147**
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax	8	-	-	-	-	-	-	-	-	**8**
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax	(129)	-	-	-	-	-	-	-	-	**(129)**
Net actuarial losses on defined benefit plans, net of tax	-	-	-	-	(20)	-	-			**(20)**
Other comprehensive (loss) income	(3)	(1)	-	-	(19)	-	-	-	2	**(21)**
Total comprehensive income (loss)	236	-	(1)	(11)	(21)	3	1	1	51	**259**
Total comprehensive income (loss) attributable to:										
Common shareholders	233	-	(1)	(11)	(21)	3	1	-	48	**252**
Non-controlling interests	3	-	-	-	-	-	-	1	3	**7**
	236	-	(1)	(11)	(21)	3	1	1	51	**259**

(1) Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

(2) Includes impacts of other IFRS adjustment for IAS 16 and IAS 37 .

Explanations of the adjustments from the Corporation's previous GAAP to IFRS related to the Consolidated Statement of Comprehensive Income for the three months and year ended Dec. 31, 2010 are as follows:

IAS 21 *The Effects of Changes in Foreign Exchange Rates*

On transition to IFRS, the cumulative net foreign exchange losses related to the translation of foreign operations was reset to nil. As a result, the amount reclassified from AOCI to net earnings in 2010 under IFRS due to the wind-up of a foreign subsidiary differed from our previous GAAP.

IAS 19 *Employee Benefits*

Under IFRS, our policy is to recognize actuarial gains and losses in OCI in the period in which they occur. Under our previous GAAP the corridor method was used, which did not require recognition of actuarial gains or losses in OCI, but instead required recognition in net earnings over time when certain conditions were met.

IAS 36 *Impairment of Assets*

Due to the recognition of asset impairment losses on transition to IFRS, translation differences arose in respect of foreign operations.

Consolidated Statement of Cash Flows Impact

The transition to IFRS changed the presentation of several items on the Consolidated Statement of Cash Flows. The most significant of these changes is the effects of applying the equity method of accounting to our interest in jointly controlled entities, versus the proportionate consolidation method used under our previous GAAP. Our share of the cash and cash equivalents and the cash flow changes of equity accounted jointly controlled entities are no longer presented within each line item of the operating, investing, or financing activities sections of the Consolidated Statement of Cash Flows, and instead, cash distributions received from equity accounted jointly controlled entities are presented as an operating activity and cash returns of invested capital and additional cash invested in equity accounted jointly controlled entities are presented as an investing activity. The capitalization of costs associated with planned major maintenance and inspection activities that were expensed under our previous GAAP will result in these cash expenditures being reported as an investing activity under IFRS. Under our previous GAAP these expenditures impacted cash flow from operations.

SUPPLEMENTAL INFORMATION

		Dec. 31, 2011	Dec. 31, 2010
Closing market price (TSX) ($)		**21.02**	21.15
Price range for the last 12 months (TSX) ($)	High	**23.24**	23.98
	Low	**19.45**	19.61
Debt to invested capital including non recourse debt (%)		**52.4**	53.1
Debt to invested capital excluding non recourse debt (%)		**49.9**	50.7
Return on equity attributable to common shareholders (%)		**10.6**	9.6
Comparable return on equity attributable to common shareholders(1), (2) (%)		**8.4**	8.0
Return on capital employed(1) (%)		**8.8**	6.6
Comparable return on capital employed(1), (2) (%)		**7.5**	6.3
Cash dividends per share(1) ($)		**1.16**	1.16
Price/comparable earnings ratio(1) (times)		**20.4**	21.8
Earnings coverage(1) (times)		**2.7**	2.2
Dividend payout ratio based on net earnings(1) (%)		**66.9**	125.1
Dividend payout ratio based on comparable earnings(1), (2) (%)		**84.3**	149.8
Dividend payout ratio based on funds from operations(1), (2) (%)		**24.0**	39.6
Dividend yield(1) (%)		**5.5**	5.5
Cash flow to debt(1) (%)		**20.2**	19.6
Cash flow to interest coverage(1) (times)		**4.4**	4.6

(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.

RATIO FORMULAS

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

Return on common shareholders' equity = 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/comparable earnings ratio = current period's close price / comparable earnings per share

Earnings coverage = (net earnings attributable to common shareholders+ income taxes + net interest) / (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 close price

Cash flow to debt = cash flow from operating activities before changes in working capital / average debt

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

Alberta 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.

Availability - A measure of 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 unit (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.

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.

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

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.

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