TransAlta™

TRANSALTA CORPORATION
THIRD QUARTER REPORT FOR 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 27, 2011. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

BASIS OF PRESENTATION AND TRANSITION TO IFRS

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 have had an impact on the results of our operations are discussed within the applicable sections of this MD&A, and in more detail in the Accounting Changes section of this MD&A.

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of the Corporation as at and for the three and nine months ended Sept. 30, 2011, which have been prepared using IFRS, and should also be read in conjunction with the audited consolidated financial statements, which were prepared using Canadian GAAP, and the MD&A, contained within our 2010 Annual Report. All comparative figures have been restated using IFRS, 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 MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Condensed Consolidated Statements of Earnings and Condensed Consolidated Statements of Financial Position items. While individual line items in the Condensed Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of these items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive Income ("AOCI") in the equity section of the Condensed Consolidated Statements of Financial Position.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Availability (%)(1)	**83.9**	91.0	**83.7**	88.1
Production (GWh)(1)	**10,368**	12,742	**29,350**	35,857
Revenues	**629**	651	**1,962**	1,894
Gross margin(2)	**371**	336	**1,307**	1,037
Operating income(2)	**111**	85	**537**	288
Net earnings attributable to common shareholders	**50**	40	**266**	163
Net earnings per share attributable to common shareholders, basic and diluted	**0.22**	0.18	**1.20**	0.74
Comparable earnings per share(2)	**0.27**	0.18	**0.91**	0.60
Comparable EBITDA(2)	**246**	217	**804**	660
Funds from operations(2)	**168**	175	**620**	571
Funds from operations per share(2)	**0.75**	0.80	**2.79**	2.60
Cash flow from operating activities	**221**	224	**512**	521
Free cash (deficiency) flow(2)	**(7)**	26	**172**	116
Dividends paid per common share	**0.29**	0.29	**0.87**	0.87

As at	**Sept. 30, 2011**	Dec. 31, 2010
Total assets	**9,709**	9,635
Total long-term liabilities	**5,149**	5,009

AVAILABILITY & PRODUCTION

Availability for the three months ended Sept. 30, 2011 decreased compared to the same period in 2010 primarily due to higher planned and unplanned outages at Centralia Thermal, higher planned and unplanned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities, and higher planned and unplanned outages at natural gas-fired facilities.

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(1) Production and availability 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 (deficiency) flow are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

Availability for the nine months ended Sept. 30, 2011 decreased compared to the same period in 2010 primarily due to higher planned and unplanned outages at Centralia Thermal partially offset by lower planned and unplanned outages at the Alberta coal PPA facilities.

Production for the three months ended Sept. 30, 2011 decreased 2,374 gigawatt hours ("GWh") compared to the same period in 2010 due to the shut down at Sundance Units 1 and 2[(1)], higher planned and unplanned outages at the Alberta coal PPA facilities, higher planned and unplanned outages at Centralia Thermal, and lower production at natural gas-fired facilities, being partially offset by the commencement of commercial operations of Keephills Unit 3, lower economic dispatching at Centralia Thermal, and higher hydro volumes.

Production for the nine months ended Sept. 30, 2011 decreased 6,507 GWh compared to the same period in 2010 due to the shut down at Sundance Units 1 and 2[(1)], higher economic dispatching at Centralia Thermal, higher planned and unplanned outages at Centralia Thermal, the sale of the Meridian facility, and the decommissioning of Wabamun, partially offset by lower planned and unplanned outages at the Alberta coal PPA facilities, higher wind volumes, higher hydro volumes, and the commencement of commercial operations of Keephills Unit 3.

The outages at Centralia Thermal did not negatively impact our gross margins for the three and nine months ended Sept. 30, 2011 as we were able to extend our planned and unplanned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Availability, after adjusting for the higher economic dispatching at Centralia, was 88.3 per cent and 88.2 per cent for the three and nine months ended Sept. 30, 2011, respectively.

NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings attributable to common shareholders for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net earnings attributable to common shareholders, 2010	40	163
(Decrease) increase in Generation gross margins	(2)	60
Mark-to-market movements - Generation	(5)	130
Increase in Energy Trading gross margins	42	80
Increase in operations, maintenance, and administrative costs	(19)	(19)
Decrease (increase) in depreciation expense	10	(2)
Increase in gain on sale of assets	-	3
Increase in asset impairment charges	(5)	(14)
Increase in net interest expense	(5)	(21)
Increase in equity income	3	8
Increase in income tax expense	(5)	(102)
Increase in net earnings attributable to non-controlling interests	(1)	(7)
Increase in preferred share dividends	(4)	(11)
Other	1	(2)
Net earnings attributable to common shareholders, 2011	**50**	**266**

(1) Refer to Sundance Units 1 and 2 shut down under the Significant Events section of this MD&A for further discussion.

Generation gross margins, excluding the impact of mark-to-market movements, for the three months ended Sept. 30, 2011 increased compared to the same period in 2010 primarily due to higher hydro margins and the commencement of commercial operations of Keephills Unit 3, partially offset by the sale of the Meridian facility, lower recoveries from the Poplar Creek base plant which we no longer operate, and higher planned and unplanned outages at the Alberta coal PPA facilities. The lower recoveries at the Poplar Creek base plant are offset by lower operations, maintenance, and administration ("OM&A") costs.

For the nine months ended Sept. 30, 2011, generation gross margins, excluding the impact of mark-to-market movements, increased compared to the same period in 2010 primarily due to higher hydro margins, lower planned and unplanned outages at the Alberta coal PPA facilities, favourable pricing, the commencement of commercial operations of Keephills Unit 3, and higher wind volumes, partially offset by lower recoveries from the Poplar Creek base plant which we no longer operate, the sale of the Meridian facility, and the decommissioning of Wabamun. The lower recoveries at Poplar Creek base plant are offset by lower OM&A costs.

Mark-to-market movements decreased for the three months ended Sept. 30, 2011 compared to the same period in 2010 because of certain hedges being deemed ineffective in 2011. The mark-to-market gains on the ineffective hedges were recognized in earnings during the first quarter at the time the hedges were deemed ineffective. If the hedges had not been deemed ineffective, the mark-to-market gains would have been recognized in the third quarter.

Mark-to-market movements increased for the nine months ended Sept. 30, 2011 compared to the same period in 2010 due to the recognition of unrealized gains resulting from certain power hedging relationships being deemed ineffective and increased weakening in market prices in the Pacific Northwest relative to our hedged prices.

Energy Trading gross margins increased for the three months ended Sept. 30, 2011 compared to the same period in 2010 due to strong trading results in the Western regions. These results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing and reduced electricity demand.

For the nine months ended Sept. 30, 2011, Energy Trading gross margins increased compared to the same period in 2010 due to strong trading results in the Western regions during the second and third quarters 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 and reduced electricity demand.

OM&A costs for the three months ended Sept. 30, 2011 increased compared to the same periods in 2010 primarily due to higher compensation costs associated with strong results, costs associated with several productivity initiatives, and the write off of certain wind development costs, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

For the nine months ended Sept. 30, 2011 OM&A costs increased compared to the same period in 2010 due to the write off 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 Sept. 30, 2011 decreased compared to the same period in 2010 primarily due to a current period adjustment to the Wabamun decommissioning and restoration provision and changes to estimated residual values.

For the nine months ended Sept. 30, 2011, depreciation expense increased compared to the same period in 2010 primarily due to an increased asset base, the writedown of capital spares, and the impact of the 2010 decrease in Wabamun decommissioning and restoration costs partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Asset impairment charges for the three and nine months ended Sept. 30, 2011 increased compared to the same period in 2010 due to the recognition of pre-tax impairment charges on assets within the renewables fleet in order to write these assets down to their fair values.

Net interest expense for the three and nine months ended Sept. 30, 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.
Equity income for the three months ended Sept. 30, 2011 increased compared to the same period in 2010 primarily due to lower planned and unplanned outages.

For the nine months ended Sept. 30, 2011, equity income increased compared to the same period in 2010 primarily due to lower planned and unplanned outages and the realization of a gain on the sale of a property, partially offset by lower income tax recoveries and unfavourable foreign exchange rates.

The income tax expense for the three months ended Sept. 30, 2011 increased compared to the same period in 2010 due to higher pre-tax earnings in 2011.

For the nine months ended Sept. 30, 2011, income tax expense increased compared to the same period in 2010 due to higher overall pre-tax earnings, including higher U.S. earnings on the recognition of unrealized gains resulting from ineffectiveness of hedging relationships, and an income tax recovery in 2010 related to the resolution of certain tax matters.

Net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2011 increased compared to the same period in 2010 due to higher earnings at TransAlta Cogeneration, L.P. ("TA Cogen").

The preferred share dividends for the three and nine months ended Sept. 30, 2011 increased compared to the same periods in 2010 due to the issuance of preferred shares in the fourth quarter of 2010.

FUNDS FROM OPERATIONS AND FREE CASH (DEFICIENCY) FLOW

Funds from operations for the three months ended Sept. 30, 2011 decreased $7 million compared to the same period in 2010 primarily due to lower net earnings after adjusting for the impact of certain non-cash foreign exchange and risk management mark-to-market gains.

For the nine months ended Sept. 30, 2011, funds from operations increased $49 million compared to the same period in 2010 primarily due to higher net earnings.

Free cash (deficiency) flow for the three months ended Sept. 30, 2011 decreased $33 million compared to the same period in 2010 due to the decrease in funds from operations, higher preferred share dividends, and higher sustaining capital expenditures partially offset by lower distributions to subsidiaries' non-controlling interests.

For the nine months ended Sept. 30, 2011, free cash (deficiency) flow increased $56 million compared to the same period in 2010 due to the increase in funds from operations and lower common share dividends paid in cash as a result of the Dividend Reinvestment and Share Purchase ("DRASP") Plan partially offset by higher sustaining capital expenditures and higher preferred share dividends.

SIGNIFICANT EVENTS

Three months ended Sept. 30, 2011

Asset Impairment Charges

During the third quarter of 2011, we recognized a pre-tax impairment charge of $5 million related to two assets within the renewables fleet. The impairment resulted from operational factors that impacted the expected useful lives of the assets. The impairment loss is included in the Generation segment.

Keephills Unit 3

On Sept. 1, 2011, our 450 megawatt ("MW") Keephills Unit 3 thermal facility, of which we have a 50 per cent ownership interest, began commercial operations. The total cost of the project is estimated to be $1.98 billion.

Sale of Grande Prairie Facility

On July 27, 2011, we signed an agreement to sell our interest in the biomass facility located in Grande Prairie. This deal closed on Oct. 1, 2011.

President and Chief Executive Officer

On July 27, 2011, we announced that TransAlta's President and Chief Executive Officer Steve Snyder will retire, effective Jan. 1, 2012. Dawn Farrell, TransAlta's Chief Operating Officer, will succeed Mr. Snyder as President and Chief Executive Officer on Jan. 2, 2012.

Nine months ended Sept. 30, 2011

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 of our Sundance facility due to the mechanical failure of critical generator components. In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. Since the event, we have recorded an after-tax charge of $16 million, or 50 per cent of the penalties, as calculated under the PPA, pending a resolution of this matter.

On Oct. 20, 2010, the Balancing Pool confirmed our determination that the mechanical failure met the requirements of a HILP event under the PPA. On July 5, 2011, the Balancing Pool purported to rescind its earlier determination. Neither action is a conclusive finding of a force majeure event, nor does either provide a definitive resolution to the dispute. Management continues to be of the view that the event constitutes both a HILP and force majeure and that they will be resolved in TransAlta's favour. The arbitration hearing has been set for May 2012. Pending a resolution of this matter, we may be required to pay to the PPA Buyers the penalties as calculated under the PPA and record an additional $16 million charge to earnings. There is no additional impact to earnings at this time as the facility is operating at full capacity. The unit may be operated in that manner for as long as our monitoring indicates that it can be operated safely, subject to the terms of the agreement, market conditions and other operating requirements. The previously announced major maintenance at this facility remains scheduled for the middle of 2012.

Bone Creek

On June 1, 2011, our 19 MW Bone Creek hydro facility began commercial operations. The total capital cost of the project was approximately $52 million.

Centralia Coal

On April 29, 2011, the Washington State Governor signed the TransAlta Energy Bill (the "Bill") into law. The Bill represents a collaborative agreement reached with the Governor's office, state legislators, and local environmental groups to establish a framework to transition from coal-fired energy produced at the Centralia Coal plant by 2025. The Memorandum of Agreement, which is part of the Bill, must be signed by the Governor no later than Jan. 1, 2012. We will continue to work with the State government and other impacted parties to successfully achieve and implement the transition plan.

The Bill, and associated Memorandum of Agreement, includes the following key elements:

- One unit will be shut down by the end of 2020 and the other by the end of 2025, at which time the site will be restored to an industrial land use standard;
- We will install Selective Non-Catalytic Reduction emission reduction technology before Jan. 1, 2013 and Washington State and the environmental community will advocate to the Environmental Protection Agency (“EPA”) that we be exempt from installing more expensive Selective Catalytic Reduction (“SCR”) technology. In the event the EPA imposes installation of SCRs at Centralia Coal, we are relieved of our obligations under the Bill;
- We will commit to fund $55 million over the life of the facility to support economic development, promoting energy efficiency and developing energy technologies related to the improvement of the environment;
- The Centralia coal plant is exempt from any Washington State imposed greenhouse gas (“GHG”) regulations;
- We are no longer restricted to power contract terms of less than five years and Washington State Utilities that enter into contracts with Centralia Coal are permitted to earn a return on the contracts; and
- Washington State will provide expedited permitting for a replacement natural gas fired generation facility, which would also be exempt from Washington State GHG regulations.

Sale of Meridian

On April 1, 2011, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta, closed the sale of its 50 per cent interest in the Meridian facility. The sale was effective Jan. 1, 2011. As a result, we realized a pre-tax gain of $3 million during the second quarter.

Asset Impairment Charges

During the second quarter of 2011, we completed an impairment assessment based on fair value estimates derived from the long range forecast and prices evidenced in the market place. As a result, we recorded a pre-tax impairment charge of $9 million on an asset within the renewables fleet. This impairment is included in the Generation segment.

New Richmond

On March 28, 2011, we announced that we had received approval from the Government of Quebec to proceed with the construction of the 68 MW New Richmond wind project located on the Gaspé Peninsula. New Richmond is contracted under a 20-year Electricity Supply Agreement with Hydro-Québec Distribution. The cost of the project is estimated to be approximately $205 million and commercial operations are expected to commence during the fourth quarter of 2012.

Sundance Units 1 and 2 Shut Down

In December 2010, Unit 1 and Unit 2 of our Sundance coal-fired generation facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units, with potential production of 1,236 GWh and 3,669 GWh, were unavailable for the three and nine months ended Sept. 30, 2011, respectively.

We are pursuing all our remedies under the PPA resulting from these events. Firstly, under the terms of the PPA for these units, we notified the PPA Buyer and the Balancing Pool of a force majeure event. To the extent the event meets the force majeure criteria set out in the PPA, we believe we are entitled to receive our PPA capacity payments and are protected from having to pay penalties for the units' lack of availability and as a result, we do not expect any material adverse effect on our results or operations. Secondly, on Feb. 8, 2011, we issued a notice of termination for destruction on Sundance Units 1 and 2 under the terms of the PPA. This action was based on the determination that the physical state of the boilers was such that the units cannot be economically restored to service under the terms of the PPA. To the extent the event meets the termination for destruction criteria set out in the PPA, we believe we are entitled to recover the net book value specified in the PPA, and as a result, we do not expect any material financial impact.

On Feb. 18, 2011, the PPA Buyer provided notice that it intends to dispute the notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. The binding arbitration process to resolve the dispute is underway. The arbitration panel identified dates in March and April 2012 to hear these claims and unless timelines are shortened by agreement of the parties, indicated that its decision would be forthcoming in mid-2012.

Although no assurance can be given as to the timing or ultimate outcome of these matters, which could impact cash flows during the interim period, we believe that they will be resolved in our favour.

Change in Estimated Residual Values

During the first quarter of 2011, management completed a comprehensive review of the residual values of all of our generating assets, having regard for, among other things, expectations about the future condition of the assets, metal volumes, as well as other market-related factors. As a result, estimated residual values were revised resulting in depreciation decreasing by $4 million and $10 million for the three and nine months ended Sept. 30, 2011 compared to the same period in 2010. Depreciation for the year ended Dec. 31, 2011 is expected to be lower by approximately $13 million.

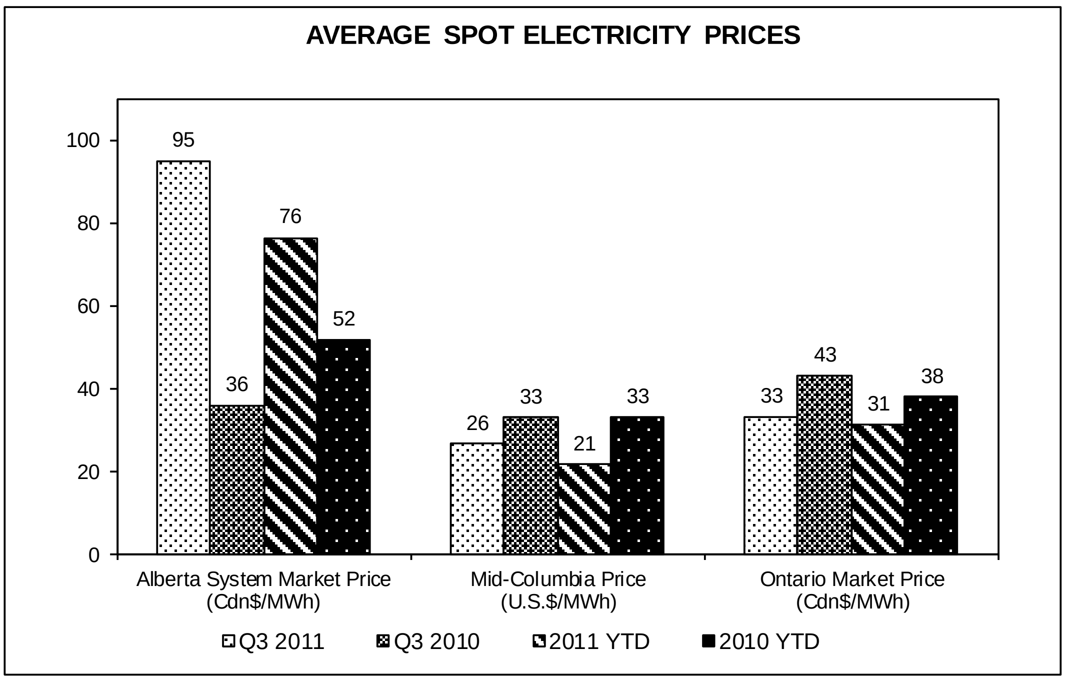
BUSINESS ENVIRONMENT

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Pacific Northwest, 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 2010 Annual Report.

Electricity Prices

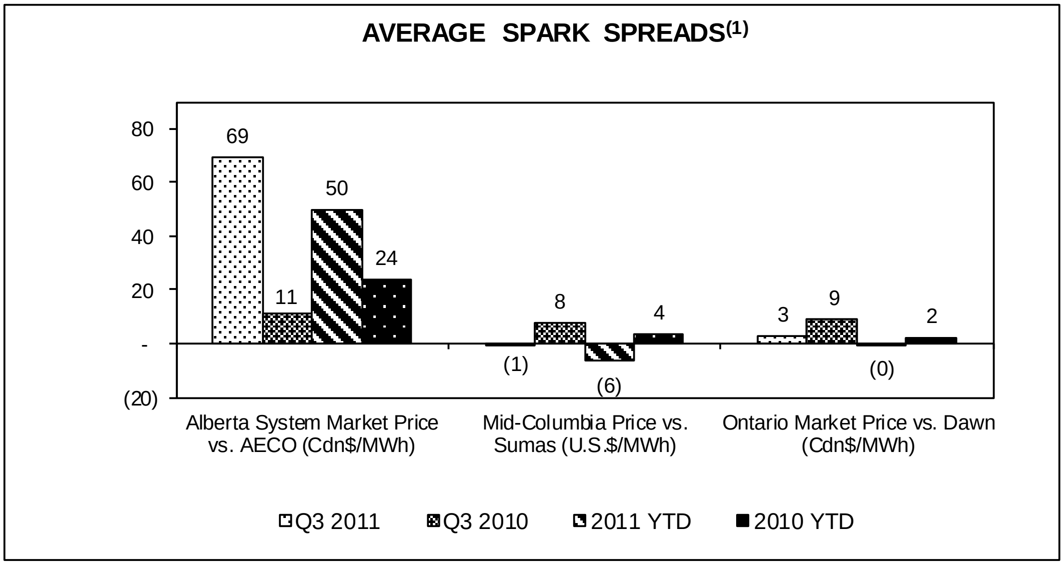
Please refer to the Business Environment section of our 2010 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices on our business, as well as our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the three and nine months ended Sept. 30, 2011 and 2010 in our three major markets are shown in the following graphs.



For the three and nine months ended Sept. 30, 2011, average spot prices increased in Alberta and decreased in the Pacific Northwest and Ontario compared to the same period in 2010. In Alberta, the increase was due to load growth from the prior year and supply tightening in the market. In the Pacific Northwest and Ontario, prices decreased due to increased hydro generation. In Ontario, prices also decreased due to lower natural gas prices and lower demand.

During the third quarter of 2011, more than 90 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 for the balance of 2011 ranging from $60 to $65 per megawatt hour (“MWh”) in Alberta, and from U.S.$50 to U.S.$55 per MWh in the Pacific Northwest.



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

For the three and nine months ended Sept. 30, 2011, average spark spreads increased in Alberta and decreased in the Pacific Northwest and Ontario compared to the same period in 2010. In Alberta, average spark spreads were higher due to higher power prices. In the Pacific Northwest and Ontario, average spark spreads decreased as a result of lower power prices. In the Pacific Northwest, average spark spreads were also lower due to higher natural gas prices.

GENERATION: *TransAlta owns and operates hydro, wind, geothermal, biomass, 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 2010 Annual Report.*

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 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, and to the Accounting Changes section of this MD&A, for further details.

GENERATION OPERATIONS*:* *During 2011, we began commercial operations at Keephills Unit 3, a 450 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 Sept. 30, 2011, our generating assets had 8,192 MW of gross generating capacity[1] in operation (7,850 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 produced by these assets are as follows:

	2011				2010	
3 months ended Sept. 30	**Total**	**Comparable adjustments[2]**	**Comparable total[2]**	**Per installed MWh**	Total	Per installed MWh
Revenues	**584**	**9**	**593**	**32.78**	648	34.42
Fuel and purchased power	**258**	**-**	**258**	**14.26**	315	16.73
Gross margin	**326**	**9**	**335**	**18.52**	333	17.69
Operations, maintenance, and administration	**100**	**-**	**100**	**5.53**	102	5.42
Depreciation and amortization	**111**	**-**	**111**	**6.14**	120	6.37
Taxes, other than income taxes	**7**	**-**	**7**	**0.39**	7	0.37
Intersegment cost allocation	**2**	**-**	**2**	**0.11**	1	0.05
Operating expenses	**220**	**-**	**220**	**12.17**	230	12.21
Operating income	**106**	**9**	**115**	**6.36**	103	5.48
Installed capacity (GWh)	**18,088**		**18,088**		18,826	
Production (GWh)	**9,826**		**9,826**		12,161	
Availability (%)	**83.0**		**83.0**		91.2	

	2011				2010	
9 months ended Sept. 30	**Total**	**Comparable adjustments[2]**	**Comparable total[2]**	**Per installed MWh**	Total	Per installed MWh
Revenues	**1,865**	**(125)**	**1,740**	**33.06**	1,877	33.24
Fuel and purchased power	**655**	**-**	**655**	**12.44**	857	15.18
Gross margin	**1,210**	**(125)**	**1,085**	**20.62**	1,020	18.06
Operations, maintenance and administration	**309**	**(5)**	**304**	**5.78**	317	5.61
Depreciation and amortization	**333**	**(4)**	**329**	**6.25**	332	5.88
Taxes, other than income taxes	**21**	**-**	**21**	**0.40**	21	0.37
Intersegment cost allocation	**6**	**-**	**6**	**0.11**	4	0.07
Operating expenses	**669**	**(9)**	**660**	**12.54**	674	11.93
Operating income	**541**	**(116)**	**425**	**8.08**	346	6.13
Installed capacity (GWh)	**52,634**		**52,634**		56,462	
Production (GWh)	**27,753**		**27,753**		34,216	
Availability (%)	**82.9**		**82.9**		87.8	

(1) We measure capacity as net maximum capacity (see glossary for definition of this and other key items) which is consistent with industry standards.

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

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 Sept. 30, 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	5,237	7,022	229	109	120	32.61	15.52	17.09
Gas	500	841	19	6	13	22.59	7.13	15.46
Renewables	827	2,939	54	3	51	18.37	1.02	17.35
Total Western Canada	**6,564**	**10,802**	**302**	**118**	**184**	**27.96**	**10.92**	**17.04**
Gas	898	1,656	91	51	40	54.95	30.80	24.15
Renewables	242	1,459	23	1	22	15.76	0.69	15.07
Total Eastern Canada	**1,140**	**3,115**	**114**	**52**	**62**	**36.60**	**16.69**	**19.91**
Coal	1,767	2,961	147	79	68	49.65	26.68	22.97
Gas	355	1,210	30	9	21	24.79	7.44	17.35
Total International	**2,122**	**4,171**	**177**	**88**	**89**	**42.44**	**21.10**	**21.34**
	9,826	**18,088**	**593**	**258**	**335**	**32.78**	**14.26**	**18.52**

3 months ended Sept. 30, 2010	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	6,183	7,744	209	91	118	26.99	11.75	15.24
Gas	787	1,084	49	14	35	45.20	12.92	32.28
Renewables	627	2,751	22	3	19	8.00	1.09	6.91
Total Western Canada	7,597	11,579	280	108	172	24.18	9.33	14.85
Gas	1,110	1,656	109	63	46	65.82	38.04	27.78
Renewables	272	1,340	26	2	24	19.40	1.49	17.91
Total Eastern Canada	1,382	2,996	135	65	70	45.06	21.70	23.36
Coal	2,626	3,037	197	127	70	64.87	41.82	23.05
Gas	556	1,214	36	15	21	29.65	12.36	17.29
Total International	3,182	4,251	233	142	91	54.81	33.40	21.41
	12,161	18,826	648	315	333	34.42	16.73	17.69

9 months ended Sept. 30, 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	16,057	19,824	649	263	386	32.74	13.27	19.47
Gas	1,897	2,496	86	25	61	34.46	10.02	24.44
Renewables	2,422	8,692	155	8	147	17.83	0.92	16.91
Total Western Canada	**20,376**	**31,012**	**890**	**296**	**594**	**28.70**	**9.54**	**19.16**
Gas	2,723	4,914	308	172	136	62.68	35.00	27.68
Renewables	1,035	4,331	99	5	94	22.86	1.15	21.71
Total Eastern Canada	**3,758**	**9,245**	**407**	**177**	**230**	**44.02**	**19.15**	**24.87**
Coal	2,583	8,786	352	154	198	40.06	17.53	22.53
Gas	1,036	3,591	91	28	63	25.34	7.80	17.54
Total International	**3,619**	**12,377**	**443**	**182**	**261**	**35.79**	**14.70**	**21.09**
	27,753	**52,634**	**1,740**	**655**	**1,085**	**33.06**	**12.44**	**20.62**

(1) Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A 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.

9 months ended Sept. 30, 2010	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	18,607	23,581	592	234	358	25.10	9.92	15.18
Gas	2,595	3,162	161	57	104	50.92	18.03	32.89
Renewables	1,801	8,216	97	7	90	11.81	0.85	10.96
Total Western Canada	23,003	34,959	850	298	552	24.31	8.52	15.79
Gas	2,870	4,914	324	183	141	65.93	37.24	28.69
Renewables	906	3,976	86	5	81	21.63	1.26	20.37
Total Eastern Canada	3,776	8,890	410	188	222	46.12	21.15	24.97
Coal	6,151	9,018	525	334	191	58.22	37.04	21.18
Gas	1,286	3,595	92	37	55	25.59	10.29	15.30
Total International	7,437	12,613	617	371	246	48.92	29.41	19.51
	34,216	56,462	1,877	857	1,020	33.24	15.18	18.06

Western Canada

Our Western Canada assets consist of coal, natural gas, hydro, biomass, and wind facilities. Refer to the Discussion of Segmented Results section of our 2010 Annual Report for further details on our Western operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2010	7,597	23,003
(Higher) lower planned and unplanned outages at the Alberta coal PPA facilities	(298)	724
Higher hydro volumes	129	368
Higher wind volumes	71	253
Commencement of commercial operations of Keephills Unit 3	159	159
(Lower) higher production at natural gas-fired facilities	(20)	9
Shut down at Sundance Units 1 and 2	(667)	(2,619)
Sale of Meridian	(121)	(555)
Decommissioning of Wabamun	-	(473)
Market curtailments	(116)	(244)
Higher planned and unplanned outages at natural gas-fired facilities	(144)	(144)
Lower PPA customer demand	(28)	(137)
Other	2	32
Production, 2011	**6,564**	**20,376**

The primary factors contributing to the change in comparable gross margin[1] for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Comparable gross margin[1], 2010	172	552
Higher hydro margins	18	49
(Higher) lower planned and unplanned outages at the Alberta coal PPA facilities	(8)	40
Commencement of commercial operations of Keephills Unit 3	13	13
Higher wind volumes	3	9
Poplar Creek base plant no longer operated by TransAlta - offset in OM&A	(14)	(38)
Sale of Meridian	(5)	(12)
Decommissioning of Wabamun	-	(10)
Favourable (unfavourable) pricing[2]	7	(9)
Higher planned and unplanned outages at natural gas-fired facilities	(4)	(4)
Other	2	4
Comparable gross margin[1], 2011	**184**	**594**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2010 Annual Report for further details on our Eastern operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2010	1,382	3,776
(Lower) higher wind volumes	(28)	129
Higher planned outages at natural gas-fired facilities	(121)	(72)
Unfavourable market conditions at natural gas-fired facilities	(91)	(58)
Other	(2)	(17)
Production, 2011	**1,140**	**3,758**

The primary factors contributing to the change in gross margin for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2010	70	222
(Lower) higher wind volumes	(2)	14
Higher planned outages at natural gas-fired facilities	(3)	(3)
Other	(3)	(3)
Gross margin, 2011	**62**	**230**

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

(2) Net of any penalties paid under the Alberta PPAs during outages.

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 2010 Annual Report for further details on our International operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2010	3,182	7,437
Higher unplanned outages at Centralia Thermal	(683)	(1,937)
Lower (higher) economic dispatching at Centralia Thermal	147	(986)
Higher planned outages at Centralia Thermal	(324)	(658)
Lower production at natural gas-fired facilities	(200)	(233)
Other	-	(4)
Production, 2011	**2,122**	**3,619**

The primary factors contributing to the change in comparable gross margin[1] for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Comparable gross margin[1], 2010	91	246
Favourable pricing, primarily driven by lower purchased power prices	-	28
Lower production at Centralia Thermal	-	(3)
Unfavourable foreign exchange	(2)	(1)
Other	-	(9)
Comparable gross margin[1], 2011	**89**	**261**

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 Sept. 30, 2011 decreased compared to the same period in 2010 due to reduced costs associated with the discontinuation of management of the base plant at Poplar Creek, partially offset by costs associated with several productivity initiatives.

For the nine months ended Sept. 30, 2011 OM&A costs decreased compared to the same period in 2010 due to lower costs associated with the discontinuation of managing the base plant at Poplar Creek, partially offset by the write off of certain wind development costs during the second quarter, resulting in a one time $5 million pre-tax ($3 million after-tax) increase in OM&A of the Generation segment and costs associated with several productivity initiatives.

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

Depreciation Expense

The primary factors contributing to the change in depreciation expense for the three and nine months ended Sept. 30, 2011 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Depreciation and amortization expense, 2010	120	332
Increase in asset base	2	10
(Decrease) increase in decommissioning and restoration costs at Wabamun	(4)	5
Writedown of capital spares	-	4
Change in residual values	(4)	(10)
Sale of Meridian	(2)	(6)
Favourable foreign exchange	(2)	(6)
Other	1	4
Depreciation and amortization expense, 2011	**111**	**333**

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 Condensed 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 5* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2011 for additional information regarding our finance lease.

Fort Saskatchewan is a natural gas-fired facility that had 71 MW of gross generating capacity in operation (35 MW net ownership interest) at Sept. 30, 2011. Key operational information related to our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Availability (%)	**92.2**	89.9	**97.3**	95.7
Production (GWh)	**118**	115	**351**	368

Availability for the three and nine months ended Sept. 30, 2011 increased compared to the same periods in 2010 due to lower planned outages.

Production for the three months ended Sept. 30, 2011 was comparable to the same period in 2010.

For the nine months ended Sept. 30, 2011, production decreased by 17 GWh compared to the same period in 2010 primarily due to lower customer demand.

Finance lease income for the three and nine months ended Sept. 30, 2011 was consistent with the same periods in 2010 at $2 million and $6 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*, which was issued by the International Accounting Standards Board ("IASB") 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 Condensed 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 income" on the Condensed Consolidated Statements of Earnings. Please refer to *Note 6* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2011 for additional financial information regarding our equity accounted investments.

Our equity accounted investments 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 equity accounted investments:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Availability (%)	**98.5**	97.6	**96.4**	94.5
Production (GWh)				
Gas	**79**	122	**284**	327
Renewables	**345**	344	**962**	946
Total production	**424**	466	**1,246**	1,273

Availability for the three and nine months ended Sept. 30, 2011 increased compared to the same periods in 2010 due to lower planned and unplanned outages at our CE Gen facilities.

Production for the three and nine months ended Sept. 30, 2011 decreased compared to the same periods in 2010 due to unfavourable market conditions partially offset by lower planned and unplanned outages.

During the three months ended Sept. 30, 2011, our equity income from CE Gen and Wailuku was $14 million as compared to income of $11 million for the same period in 2010. The equity income increased primarily due to lower planned and unplanned outages.

Equity income from CE Gen and Wailuku for the nine months ended Sept. 30, 2011 was $16 million as compared to income of $8 million for the same period in 2010. The equity income increased primarily due to lower unplanned outages and the realization of a gain on the sale of property, partially offset by lower income tax recoveries and unfavourable foreign exchange rates.

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 limits, is a key measure of Energy Trading's activities.*

Energy Trading manages available generating capacity, as well as the fuel and transmission needs, of the Generation business by utilizing contracts of various durations for the forward sales of electricity and for the purchase 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 2010 Annual Report.

The results of the Energy Trading segment are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Gross margin	**45**	3	**97**	17
Operations, maintenance, and administration	**12**	4	**27**	13
Depreciation and amortization	**-**	-	**1**	1
Intersegment cost recovery	**(2)**	(1)	**(6)**	(4)
Operating expenses	**10**	3	**22**	10
Operating income	**35**	-	**75**	7

For the three months ended Sept. 30, 2011, gross margins increased relative to the same period in 2010 due to strong trading results in the Western regions. These results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing and reduced electricity demand.

Gross margin increased for the nine months ended Sept. 30, 2011 relative to the same period in 2010 due to strong trading results in the Western regions during the second and third quarters 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 and reduced electricity demand.

OM&A costs for the three and nine months ended Sept. 30, 2011 increased over the same period in 2010 due to higher compensation costs associated with strong results and costs associated with several productivity initiatives.

CORPORATE: *Our Generation and Energy Trading business 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 Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Operations, maintenance, and administration	**26**	13	**64**	51
Depreciation and amortization	**4**	5	**15**	14
Operating expenses	**30**	18	**79**	65

OM&A costs increased for the three and nine months ended Sept. 30, 2011 compared to the same periods in 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 Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Interest on debt	**57**	60	**167**	168
Interest income	**-**	(2)	**-**	(16)
Capitalized interest	**(8)**	(13)	**(31)**	(35)
Ineffectiveness on fair value hedges	**(1)**	-	**(1)**	-
Other	**-**	-	**1**	-
Interest expense	**48**	45	**136**	117
Accretion of discount on provisions	**6**	4	**15**	13
Net interest expense	**54**	49	**151**	130

The change in net interest expense for the three and nine months ended Sept. 30, 2011, compared to the same period in 2010 is shown below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net interest expense, 2010	49	130
Lower interest income primarily due to the resolution of certain outstanding tax matters in 2010	-	15
Higher interest rates	2	7
Lower capitalized interest	5	4
Higher decommissioning and restoration accretion	1	1
Favourable foreign exchange	-	(4)
Lower debt levels	(2)	(1)
Ineffective gain on fair value hedges	(1)	(1)
Net interest expense, 2011	**54**	**151**

INCOME TAXES

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Earnings before income taxes	**70**	50	**399**	176
Income attributable to non-controlling interests	**(7)**	(6)	**(27)**	(20)
Equity income	**(14)**	(11)	**(16)**	(8)
Impacts associated with certain de-designated and ineffective hedges	**9**	-	**(125)**	-
Asset impairment charges	**5**	-	**14**	-
Other non-comparable items	**-**	-	**6**	-
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**63**	33	**251**	148
Income tax (recovery) expense	**9**	4	**95**	(7)
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**2**	-	**(45)**	-
Income tax recovery related to asset impairment charges	**1**	-	**3**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	30
Income tax related to other non-comparable items	**-**	-	**2**	-
Income tax expense excluding non-comparable items	**12**	4	**55**	23
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items	**19**	12	**22**	16

The income tax expense excluding non-comparable items for the three and nine months ended Sept. 30, 2011 increased compared to the same periods in 2010 due to higher comparable earnings and changes in the composition of 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 and nine months ended Sept. 30, 2011 increased primarily due to the effect of certain deductions that do not fluctuate with earnings and changes in the composition of 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 MD&A for further discussion.

Net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2011 increased $1 million and $7 million, respectively, compared to the same periods in 2010 due to higher earnings at TA Cogen.

FINANCIAL POSITION

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2010 to Sept. 30, 2011:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	31	Increase in net earnings and increase in borrowings under credit facilities
Accounts receivable	71	Timing of customer receipts and higher revenues
Income taxes receivable	(18)	Resolution of certain tax matters
Inventory	46	Lower production at our coal facilities and higer average coal costs
Assets held for sale	(57)	Completion of sale of the Meridian facility partially offset by the sale of the Grande Prairie facility
Investments	23	Equity income and favourable foreign exchange
Risk management assets (current and long-term)	(17)	Price movements and changes in underlying positions
Other assets	(17)	Transfer of project to property, plant, and equipment
Accounts payable and accrued liabilities	(34)	Timing of payments and lower capital accruals
Collateral received	(97)	Reduction in collateral received from counterparties associated with changes in forward prices
Dividends payable	(64)	Timing of common share dividend declarations
Long-term debt (including current portion)	206	Increase in borrowings under credit facilities
Decommissioning and other provisions (current and long-term)	70	Increase in decommissioning and commercial provisions
Deferred credits and other long-term liabilities	33	Increase in defined benefit accrual
Deferred income tax liabilities	(32)	Tax effect on the increase in net risk management liabilities
Risk management liabilities (current and long-term)	107	Price movements and changes in underlying positions
Equity attributable to shareholders	(66)	Increase in net earnings, offset by movements in AOCI
Non-controlling interests	(51)	Distributions paid, partially offset by non-controlling interests' portion of net earnings

FINANCIAL INSTRUMENTS

Refer to *Note 7* of the notes to the consolidated financial statements within our 2010 Annual Report and *Note 10* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2011 for details on Financial Instruments. Refer to the Risk Management section of our 2010 Annual Report for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2010 and our transition to IFRS did not have a material effect on our accounting for financial instruments.

Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under IFRS as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is, therefore, developed using valuation models or upon internally developed assumptions or inputs. Our Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, or demand profiles. Fair values are validated on a quarterly basis by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements.

As a result of our acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro"), we also have various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts must be derived by reference to a forecast that is based on a combination of external and internal fundamental modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with counterparties that we believe to be creditworthy.

At Sept. 30, 2011, Level III financial instruments had a net liability carrying value of $14 million (Dec. 31, 2010 - $20 million).

During the three and nine months ended Sept. 30, 2011, unrealized pre-tax gains of $3 million and $207 million, respectively, were released from AOCI and recognized in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices which will change between now and the time the underlying hedged transactions are expected to occur. 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, the majority of which will occur during 2011 and 2012. 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.

We discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Sept. 30, 2011, cumulative gains of $95 million, $78 million of which was discontinued in the third quarter of 2011, will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur.

STATEMENTS OF CASH FLOWS

Our transition to IFRS changed the presentation of several items on the Condensed 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 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 Condensed 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 Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2011 compared to the same periods in 2010:

3 months ended Sept. 30	**2011**	2010	Primary factors explaining change
Cash and cash equivalents, beginning of period	**38**	32	
Provided by (used in):			
Operating activities	**221**	224	Lower cash earnings of $7 million, offset by favourable changes in working capital balances of $4 million primarily due to the timing of payments and receipts
Investing activities	**(192)**	(134)	Decrease in collateral received from counterparties of $100 million, offset by a decrease in additions to PP&E of $66 million
Financing activities	**(1)**	(71)	Increased borrowings due to higher usage of cash in investing activities
Translation of foreign currency cash	**-**	6	
Cash and cash equivalents, end of period	**66**	57	

9 months ended Sept. 30	**2011**	2010	Primary factors explaining change
Cash and cash equivalents, beginning of period	**35**	53	
Provided by (used in):			
Operating activities	**512**	521	Unfavourable changes in working capital balances of $58 million primarily due to the timing of payments and receipts offset by higher cash earnings of $49 million
Investing activities	**(411)**	(552)	Decrease in additions to PP&E of $297 million and proceeds on the sale of the Meridian facility of $30 million, offset by an $182 million decrease in collateral received from counterparties
Financing activities	**(71)**	32	Reduced borrowings and lower cash dividends on common shares
Translation of foreign currency cash	**1**	3	
Cash and cash equivalents, end of period	**66**	57	

LIQUIDITY AND CAPITAL RESOURCES

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

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

Debt

Under IFRS, debt arising through our equity accounted joint ventures is no longer presented as part of non-recourse debt. Recourse and non-recourse debt totalled $4.3 billion at Sept. 30, 2011 and $4.1 billion at Dec. 31, 2010.

Credit Facilities

At Sept. 30, 2011, we have a total of $2.0 billion (Dec. 31, 2010 - $2.0 billion) of committed credit facilities of which $0.7 billion (Dec. 31, 2010 - $1.1 billion) is not drawn and available, subject to customary borrowing conditions. At Sept. 30, 2011, the $1.3 billion (Dec. 31, 2010 - $0.9 billion) of credit utilized under these facilities is comprised of actual drawings of $1.0 billion (Dec. 31, 2010 - $0.6 billion) and of letters of credit of $0.3 billion (Dec. 31, 2010 - $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2015, with the remainder comprised of bilateral credit facilities which mature between the fourth quarter of 2012 and the third quarter of 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.7 billion available under the credit facilities, we also have $66 million of cash available.

Share Capital

On Oct. 27, 2011, we had 223.6 million common shares outstanding and 12.0 million first preferred shares outstanding.

At Sept. 30, 2011, we had 222.9 million (Dec. 31, 2010 - 220.3 million) common shares issued and outstanding. During the three months ended Sept. 30, 2011, 0.9 million (Sept. 30, 2010 - 0.7 million) common shares were issued for $17 million (Sept. 30, 2010 - $15 million). During the three months ended Sept. 30, 2011 and 2010, all the common shares were issued under the terms of the DRASP plan. During the nine months ended Sept. 30, 2011, 2.6 million (Sept. 30, 2010 - 1.1 million) common shares were issued for $52 million (Sept. 30, 2010 - $19 million). Of the 2.6 million common shares issued during the nine months ended Sept. 30, 2011, 0.1 million were issued for cash proceeds of $1 million and 2.5 million were issued for $51 million under the terms of the DRASP plan. Of the 1.1 million common shares issued during the nine months ended Sept. 30, 2010, 0.2 million were issued for cash proceeds of $1 million and 0.9 million were issued for $18 million under the terms of the DRASP plan.

We employ a variety of stock-based compensation to align employee and corporate objectives. At Sept. 30, 2011, we had 1.8 million outstanding employee stock options (Dec. 31, 2010 - 2.2 million). During the three months ended Sept. 30, 2011, a nominal number of options expired, or were exercised or cancelled (Sept. 30, 2010 - a nominal number of options expired, or were exercised or cancelled). During the nine months ended Sept. 30, 2011, 0.4 million options expired, or were exercised or cancelled (Sept. 30, 2010 - 0.1 million options expired, or were exercised or cancelled).

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At Sept. 30, 2011, we provided letters of credit totalling $302 million (Dec. 31, 2010 - $297 million) and cash collateral of $38 million (Dec. 31, 2010 - $27 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Positions under “Risk Management Liabilities” and “Decommissioning and Other Provisions”.

CLIMATE CHANGE AND THE ENVIRONMENT

On Aug. 27, 2011, the Government of Canada published in the Canada Gazette draft regulations entitled "Reduction of CO_2 Emissions from Coal-Fired Generation of Electricity". These regulations propose a 45-year end-of-life for coal-fired power units, at which point the units would have to meet a GHG emissions performance standard similar to natural gas-fired levels, or close. Should they be passed, the regulations would become effective on July 1, 2015. Under federal consultation provisions, industry, provinces and other stakeholders have 60 days to provide comments on the regulations and subsequently the federal government will consider this input in the development of the second draft.

We are currently in discussions with both the federal and Alberta governments about modifications to the regulations that would result in significant GHG emission reductions in the most economically efficient manner, and would also provide alignment with other current and future regulations on air pollutants and on natural gas generation. These discussions are expected to continue through October and November.

In the U.S., the EPA announced on Sept. 14, 2011 that it was further delaying the release of draft GHG regulations for coal-fired power plants beyond its Sept. 30, 2011 target date. It is not known when the regulations might be forthcoming or their exact form.

TransAlta is proceeding with the installation of voluntary mercury capture technology at the Centralia coal-fired plant which will be operational by 2012. That plant is also planning for the installation of additional capture technology to further reduce oxides of nitrogen ("NOx"), consistent with the Washington State Bill passed in April 2011 requiring TransAlta to begin operating such technology by Jan. 1, 2013. Both these initiatives are well in advance of the finalization of any federal regulations on mercury and NOx-related ozone.

For further details regarding these, and other matters, please refer to the discussion in the Climate Change and the Environment section of our 2010 Annual Report.

2011 OUTLOOK

In 2011, we anticipate modest growth in comparable earnings per share, funds from operations, and comparable EBITDA based upon the factors that are discussed below.

Business Environment

Power Prices

For the remainder of 2011, power prices in Alberta are expected to be higher compared to the same period last year primarily as a result of tighter supply and demand balances. In the Pacific Northwest, prices are expected to be comparable to 2010 due to low natural gas prices.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has expressed its plan to coordinate the timing and structure of its GHG regulatory framework with the U.S., although coal-fired power is being addressed separately and earlier. In the U.S., it is not clear if climate change legislation will prevail or if regulation will be applied by the EPA. Each of these outcomes could create widely different results for the energy industry in the U.S., and indirectly for Canada's regulatory approach.

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 access the risk associated with these activities.

Economic Environment

The economic environment has shown modest improvement in 2011 and we expect this trend to continue through 2011 at a slow to moderate pace.

We had no counterparty losses in the third quarter of 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.

Operations

Capacity, Production, and Availability

Generating capacity is expected to be constant for the remainder of 2011. Production is expected to increase for the remainder of 2011 due to lower planned and unplanned outages, lower economic dispatching, and the commencement of commercial operations of Keephills Unit 3. Availability is expected to increase for the remainder of 2011 due to lower planned and unplanned outages.

Commodity Hedging

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 the third quarter, approximately 95 per cent of our 2011 capacity was contracted. The average price of our short-term physical and financial contracts for the balance of 2011 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 mines are minimized through the application of standard costing. Coal costs for 2011, on a standard cost basis, are expected to increase by approximately 14 per cent compared to 2010 due to lower tonnes mined and delivered to the thermal units as a result of the shut down at Sundance Units 1 and 2.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2011 is expected to remain consistent with the prior year.

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 going forward.

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 2011 are expected to be lower than amounts previously reported under Canadian GAAP due primarily to major inspection costs being capitalized under IFRS. Under Canadian GAAP, major inspection costs were expensed as incurred.

OM&A costs for 2011 are expected to be higher than 2010 OM&A costs under IFRS primarily due to costs associated with a number of productivity initiatives, the write off of development costs, and higher compensation costs.

Energy Trading

Earnings from our Energy Trading segment are affected by prices in the market and overall strategies adopted. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our revised 2011 objective is for Energy Trading to contribute between $100 million and $125 million in gross margin. The annual objective for Energy Trading gross margin contribution has increased from prior estimates to reflect the year-to-date results.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. 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 2011 is expected to be higher than our reported 2010 net interest expense under Canadian GAAP mainly due to higher debt balances, higher variable interest rates, lower capitalized interest, and lower interest income. 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 *Note 1Y* of our notes to the unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2011, 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.

Income Taxes

The effective tax rate on earnings excluding non-comparable items for 2011 is expected to be approximately 18 to 23 per cent.

Capital Expenditures

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

Growth Capital Expenditures

We have four significant growth capital projects that are currently in progress with targeted completion date of Q4 2012. A summary of each of these significant projects and the projects we completed is outlined below:

	Total Project		2011		Target	
Project	**Estimated spend**	**Spend to date[1]**	**Estimated spend**	**Spend to date[1]**	**completion date**	**Details**
Keephills Unit 3[2]	1,010 - 1,020	993	70 - 90	64	Commercial operations began Q3 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Keephills Unit 1 uprate	34	8	5 - 15	4	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	7	10 - 20	1	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Bone Creek[3]	52	50	(0) - (5)	(4)	Commercial operations began Q2 2011	A 19 MW hydro facility in British Columbia
Sundance Unit 3 uprate	27	9	5 - 10	6	Q4 2012	A 15 MW efficiency uprate at our Sundance facility
New Richmond[4]	205	12	20 - 40	12	Q4 2012	A 68 MW wind farm in Quebec
Total growth	**1,362 - 1,372**	**1,079**	**110 - 170**	**83**		

Our estimated spend for 2011 for Bone Creek has increased by $5 million and our estimated spend for 2011 has decreased by $5 million for the Keephills Unit 1 and Sundance 3 uprates and by $10 million for the Keephills Unit 2 uprate to more accurately reflect the expected timing of related costs.

Amounts disclosed in the above chart are shown net of any joint venture contributions received or other recoveries.

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(1) Represents amounts spent as of Sept. 30, 2011. In 2011, we also spent a combined total of $6 million on Ardenville and Kent Hills 2.

(2) Keephills Unit 3 amounts spent as of Sept. 30, 2011 includes a non-capital expenditures of $7 million and a coal cost reduction of $2 million.

(3) Bone Creek amounts spent as of Sept. 30, 2011 includes a non-capital credit of $9 million.

(4) New Richmond amounts spent as of Sept. 30, 2011 includes expenditures of $5 million which had been previously included in project development costs.

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.

For 2011, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Spend to date(1)
Routine capital	Expenditures to maintain our existing generating capacity	95 - 105	85
Productivity capital	Projects to improve power production efficiency	10 - 20	14
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	25 - 30	15
Planned maintenance	Regularly scheduled major maintenance	180 - 210	136
Total sustaining expenditures		**310 - 365**	250

Details of the 2011 planned maintenance program, including major inspection costs, are outlined as follows:

	Coal	Gas and Renewables	Expected cost	Spend to date(1)
Capitalized	105 - 130	75 - 80	180 - 210	136
Expensed	0 - 0	0 - 5	0 - 5	2
	105 - 130	75 - 85	180 - 215	138

	Coal	Gas and Renewables	Expected total	Lost to date
GWh lost	2,610 - 2,620	430 - 440	3,040 - 3,060	2,676

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.

ACCOUNTING CHANGES

Transition to IFRS

On Jan. 1, 2011, we adopted IFRS for Canadian publicly accountable enterprises, as required by the Accounting Standards Board of Canada. Prior to the adoption of IFRS, we followed Canadian GAAP. While IFRS uses a conceptual framework similar to Canadian GAAP and has many similarities to Canadian GAAP, several of our significant accounting policies have changed. The

(1) Represents amounts incurred as of Sept. 30, 2011.

most significant of these accounting policy changes impacting our results of operations have been outlined in earlier sections of this MD&A (please refer to the Finance Lease and Equity Investments sections of the Generation segment discussion and to the Sustaining Capital Expenditures section of the 2011 Outlook discussion). In addition to these, there have been several other changes to our accounting policies, which are discussed below. To assist with, and in some cases, simplify, transition to IFRS, certain exemptions and elections are available for first-time adopters under IFRS 1 *First-Time Adoption of International Financial Reporting Standards* ("IFRS 1"). The most significant that we have chosen to use are also discussed below.

Arrangements That Are, or Contain a Lease: Contractual arrangements exempted from similar review under Canadian GAAP were reviewed to determine if they contained, or were, finance or operating leases. As a result of this review, in addition to our Fort Saskatchewan facility being a finance lease, several of our other PPAs and long-term contracts are considered operating lease arrangements, as we retain the operational risks. Although the nature of these arrangements has changed under IFRS, no differences arose in the way we recognize our revenues, or in how we account for the PP&E, associated with the related facilities.

Employee Future Benefits: On transition to IFRS, the cumulative net actuarial losses related to our defined benefit pension and post-employment plans were recognized in retained earnings, and will not have an impact on net earnings in future periods. Actuarial gains and losses arising subsequent to transition will be recognized in Other Comprehensive Income ("OCI") as they occur, in accordance with our accounting policy choice. Under our previous GAAP, the corridor method was used, and actuarial gains or losses were only recognized in net earnings over time, when certain conditions were met.

Foreign Exchange Gains and Losses on Translation of Foreign Operations: Our cumulative net foreign exchange losses on translation of foreign operations, net of hedges and tax, were reset to zero and recognized in retained earnings on transition, and consequently, will not have an impact on future net earnings. Foreign exchange gains or losses on translation of foreign operations arising subsequently will continue to be recognized in OCI, as under our previous GAAP.

Provisions: IFRS requires that provisions, such as obligations for decommissioning and restoration costs, are revalued at the end of each reporting period using a current market-based discount rate. Amounts arising as a result of these revaluations are recognized as a cost of the related asset, and depreciated accordingly. Under Canadian GAAP, the discount rates used were only revised in certain circumstances.

Business Combinations: Acquisitions that occurred prior to transition can continue to be measured and recorded at their previously established Canadian GAAP amounts. As a result of the use of this election, we were not required to restate our 2009 acquisition of Canadian Hydro to comply with IFRS.

Although we adopted IFRS on Jan. 1, 2011, we were required to restate our comparative 2010 annual and interim financial positions and results of operations, effective from Jan. 1, 2010. The 2010 comparative amounts have not been audited by our external auditor. *Note 1* of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2011 outlines our IFRS accounting policies and *Note 2* provides a complete list of our IFRS 1 elections; detailed reconciliations between Canadian GAAP and IFRS of shareholders' equity as at Jan. 1, Sept. 30, and Dec. 31, 2010, respectively, and of net earnings and comprehensive income for the three and nine months ending Sept. 30, and for the twelve months ending Dec. 31, 2010, respectively; and information regarding the impacts of IFRS transition on our cash flows.

Future Accounting Changes

I. IFRS Policies

Our interim financial statements as at and for the three and nine months ended Sept. 30, 2011 and 2010 and our IFRS Statements of Financial Position as at Jan.1 and Dec. 31, 2010, respectively, have been prepared using the Standards and Interpretations currently issued and expected to be effective at the end of our first annual IFRS reporting period of Dec. 31, 2011. Accounting policies currently adopted under IFRS are subject to change as a result of either a new standard being issued with an effective date of Dec. 31, 2011 or prior, or as a result of a voluntary change in accounting policy made by us during 2011. A change in an accounting policy used may result in material changes to our reported financial position, results of operations and cash flows.

II. Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements*, which replaces IAS 27 *Consolidated and Separate Financial Statements* and SIC-12 *Consolidation - Special Purpose Entities*. IFRS 10 provides a revised definition of control so that a single control model can be applied to all entities for consolidation purposes.

III. Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements*, which supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities - Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principle-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its joint arrangements. IFRS 11 also requires the use of the equity method of accounting for interests in joint ventures. Improvements in disclosure requirements are intended to allow investors to gain a better understanding of the nature, extent, and financial effects of the activities that an entity carries out through joint arrangements.

IV. Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in consolidated and unconsolidated entities, such as subsidiaries, joint arrangements, associates, and unconsolidated structured entities (special purpose entities).

V. Investments in Associates and Joint Ventures and Separate Financial Statements

Two existing standards, *IAS 28 Investments in Associates and Joint Ventures* and IAS 27 *Separate Financial Statements*, were amended. The amendments result from the issuance of IFRS 10, IFRS 11, and IFRS 12.

The requirements of the preceding new standards and amendments to existing standards, outlined in points II to V, are effective for annual periods beginning on or after Jan. 1, 2013. The disclosure requirements of IFRS 12 may be incorporated into the financial statements earlier than Jan. 1, 2013. However, early adoption of the other standards is only permitted if all five are applied at the same time. We are currently assessing the impact of adopting these new standards and amendments on the consolidated financial statements.

VI. Fair Value Measurements

In June 2011, the IASB issued IFRS 13 *Fair Value Measurements*, which establishes a single source of guidance for all fair value measurements required by other IFRS; clarifies the definition of fair value; and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability or its own equity instrument at fair value. IFRS 13 is effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. We are currently assessing the impact of adopting IFRS 13 on the consolidated financial statements.

VII. Presentation of Financial Statements

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The amendments to IAS 1 are effective for annual periods beginning on or after July 1, 2012. Earlier application is permitted. We are currently assessing the impact of adopting the amendments to IAS 1 on the consolidated financial statements.

VIII. Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits* to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service cost is presented in net earnings; finance cost is presented as part of finance costs in net earnings; and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI, effectively eliminating the option to defer the recognition of actuarial gains and losses, known as the ‘corridor method’. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. We are currently assessing the impact of adopting the amendments to IAS 19 on the consolidated financial statements.

IX. Financial Instruments

In November 2009, the IASB issued IFRS 9 *Financial Instruments* which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or fair value through profit or loss or through OCI depending on the basis of the entity’s business model for managing the financial asset and the contractual cash flow characteristics of the financial asset.

In October 2010, the IASB issued additions to IFRS 9 *Financial Instruments* regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require the portion of the change in fair value due to changes in the entity’s own credit risk be presented in OCI, rather than within net earnings.

The requirements are effective for annual periods beginning on or after Jan. 1, 2013, and must be applied retrospectively. Earlier adoption is permitted. The IASB has recently issued an exposure draft which proposes to postpone the mandatory application of IFRS 9 until 2015. We are currently assessing the impact of adopting IFRS 9 on the consolidated financial statements.

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 Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Revenues	**629**	651	**1,962**	1,894
Fuel and purchased power	**258**	315	**655**	857
Gross margin	**371**	336	**1,307**	1,037
Operations, maintenance, and administration	**138**	119	**400**	381
Depreciation and amortization	**115**	125	**349**	347
Taxes, other than income taxes	**7**	7	**21**	21
Operating expenses	**260**	251	**770**	749
Operating income	**111**	85	**537**	288
Finance lease income	**2**	2	**6**	6
Equity income	**14**	11	**16**	8
Gain on sale of assets	**-**	-	**3**	-
Other income	**1**	-	**2**	-
Foreign exchange gain	**1**	1	**-**	4
Asset impairment charges	**(5)**	-	**(14)**	-
Net interest expense	**(54)**	(49)	**(151)**	(130)
Earnings before income taxes	**70**	50	**399**	176
Income tax expense (recovery)	**9**	4	**95**	(7)
Net earnings	**61**	46	**304**	183
Non-controlling interests	**7**	6	**27**	20
Net earnings attributable to TransAlta shareholders	**54**	40	**277**	163
Preferred share dividends	**4**	-	**11**	-
Net earnings attributable to common shareholders	**50**	40	**266**	163

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 for 2011, we exclude the impact related to certain power hedging relationships 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, the majority of which will occur during 2011 and 2012. 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 addition, we have excluded the gain on the sale of the Meridian facility, the write off of acquired wind development costs, the writedown of certain capital spares, and asset impairment charges as these items are not considered regular business activities.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Net earnings attributable to common shareholders	**50**	40	**266**	163
Impacts associated with certain de-designated and ineffective hedges, net of tax	**7**	-	**(80)**	-
Gain on sale of the Meridian facility, net of tax	**-**	-	**(2)**	-
Write off of wind development costs, net of tax	**-**	-	**3**	-
Writedown of capital spares, net of tax	**-**	-	**3**	-
Asset impairment charges, net of tax	**4**	-	**11**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**-**	(30)
Earnings on a comparable basis	**61**	40	**201**	133
Weighted average number of common shares outstanding in the period	**223**	220	**222**	220
Earnings on a comparable basis per share	**0.27**	0.18	**0.91**	0.60

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 Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Operating income	**111**	85	**537**	288
Depreciation and amortization per the Condensed Consolidated Statements of Cash Flows(1)	**126**	132	**383**	372
EBITDA	**237**	217	**920**	660
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**9**	-	**(125)**	-
Write off of wind development costs, pre-tax	**-**	-	**5**	-
Writedown of capital spares, pre-tax	**-**	-	**4**	-
Comparable EBITDA	**246**	217	**804**	660

(1) To calculate EBITDA, we use depreciation and amortization per the Condensed 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 Condensed Consolidated Statements of Earnings.

Funds from Operations and Funds from Operations per Share

Presenting funds from operations and funds from operations per share from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with prior periods' results. Funds from operations per share is calculated using the weighted average common shares outstanding during the period.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Cash flow from operating activities	**221**	224	**512**	521
Change in non-cash operating working capital balances	**(53)**	(49)	**108**	50
Funds from operations	**168**	175	**620**	571
Weighted average number of common shares outstanding in the period	**223**	220	**222**	220
Funds from operations per share	**0.75**	0.80	**2.79**	2.60

Free Cash (Deficiency) Flow

Free cash (deficiency) 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 recourse debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash (deficiency) 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 Sept. 30, 2011 represents total additions to PP&E and intangibles per the Condensed Consolidated Statements of Cash Flows less $18 million ($17 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2010, we invested $115 million ($113 million net of joint venture contributions) in growth projects. For the nine months ended Sept. 30, 2011 and 2010, we invested $84 million ($83 million net of joint venture contributions) and $390 million ($383 million net of joint venture contributions), respectively, in growth projects.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Cash flow from operating activities	**221**	224	**512**	521
Add (Deduct):				
Changes in working capital	**(53)**	(49)	**108**	50
Sustaining capital expenditures	**(114)**	(85)	**(250)**	(242)
Dividends paid on common shares	**(48)**	(49)	**(143)**	(169)
Dividends paid on preferred shares	**(4)**	-	**(11)**	-
Distributions paid to subsidiaries' non-controlling interests	**(9)**	(15)	**(44)**	(44)
Free cash (deficiency) flow	**(7)**	26	**172**	116

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

SELECTED QUARTERLY INFORMATION

	Q4 2010	Q1 2011	Q2 2011	**Q3 2011**
Revenue	779	818	515	**629**
Net earnings attributable to common shareholders	93	204	12	**50**
Net earnings per share attributable to common shareholders, basic and diluted	0.42	0.92	0.05	**0.22**
Comparable earnings per share	0.37	0.34	0.29	**0.27**

	Q4 2009[1]	Q1 2010	Q2 2010	Q3 2010
Revenue	763	696	547	651
Net earnings attributable to common shareholders	79	60	63	40
Net earnings per share attributable to common shareholders, basic and diluted	0.37	0.27	0.29	0.18
Comparable earnings per share	0.40	0.27	0.15	0.18

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

DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the *Securities Exchange Act of 1934* ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Sept. 30, 2011, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

(1) Q4 2009 represents Canadian GAAP figures.

FORWARD LOOKING STATEMENTS

This MD&A, 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 as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from those projected.

In particular, this MD&A 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 upgrades, 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 plans to invest in existing and new capacity, and the expected return on those investments; 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; our plans to install mercury control equipment at our Alberta Thermal operations and our initiative to reduce nitrogen oxide and mercury emissions from our Centralia Plant; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; expectations relating to the renegotiation of certain of the collective bargaining agreements to which we are party; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; expectations for the outcome of existing or potential legal and contractual claims; and expectations for the ability to access capital markets at reasonable terms.

Factors that may adversely impact our forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) energy trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) our provision for income taxes; (xix) legal and contractual proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2010 Annual Report and under the heading "Risk Factors" in our 2010 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 you that projected results or events will be achieved.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2011**	2010	**2011**	2010
Revenues	**629**	651	**1,962**	1,894
Fuel and purchased power *(Note 4)*	**258**	315	**655**	857
	371	336	**1,307**	1,037
Operations, maintenance, and administration *(Note 4)*	**138**	119	**400**	381
Depreciation and amortization	**115**	125	**349**	347
Taxes, other than income taxes	**7**	7	**21**	21
	260	251	**770**	749
	111	85	**537**	288
Finance lease income *(Note 5)*	**2**	2	**6**	6
Equity income *(Note 6)*	**14**	11	**16**	8
Gain on sale of assets *(Note 3)*	**-**	-	**3**	-
Other income	**1**	-	**2**	-
Foreign exchange gain *(Note 11)*	**1**	1	**-**	4
Asset impairment charges *(Note 14)*	**(5)**	-	**(14)**	-
Net interest expense *(Notes 7 and 11)*	**(54)**	(49)	**(151)**	(130)
Earnings before income taxes	**70**	50	**399**	176
Income tax expense (recovery) *(Note 8)*	**9**	4	**95**	(7)
Net earnings	**61**	46	**304**	183
Net earnings attributable to:				
TransAlta shareholders	**54**	40	**277**	163
Non-controlling interests *(Note 9)*	**7**	6	**27**	20
	61	46	**304**	183
Net earnings attributable to TransAlta shareholders	**54**	40	**277**	163
Preferred share dividends *(Note 21)*	**4**	-	**11**	-
Net earnings attributable to common shareholders	**50**	40	**266**	163
Weighted average number of common shares outstanding in the period *(millions)*	**223**	220	**222**	220
Net earnings per share attributable to common shareholders, basic and diluted	**0.22**	0.18	**1.20**	0.74

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2011**	2010	**2011**	2010
Net earnings	**61**	46	**304**	183
Other comprehensive (loss) income				
Gains (losses) on translating net assets of foreign operations	**87**	(14)	**43**	(22)
(Losses) gains on financial instruments designated as hedges of foreign operations, net of tax(1)	**(68)**	8	**(42)**	10
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**17**	107	**(38)**	224
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(3)	**-**	1	**-**	8
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(54)**	(11)	**(203)**	(83)
Net actuarial gains (losses) on defined benefit plans, net of tax(5)	**2**	1	**(19)**	(33)
Other comprehensive (loss) income	**(16)**	92	**(259)**	104
Comprehensive income	**45**	138	**45**	287

Total comprehensive income attributable to:				
Common shareholders	**40**	147	**22**	282
Non-controlling interests	**5**	(9)	**23**	5
	45	138	**45**	287

(1) Net of income tax recovery of 10 and 6 for the three and nine months ended Sept. 30, 2011 (2010 - 2 expense and 2 expense), respectively.

(2) Net of income tax expense of 3 and 4 for the three and nine months ended Sept. 30, 2011 (2010 - 64 expense and 124 expense), respectively.

(3) Net of income tax of nil for the three and nine months ended Sept. 30, 2011 (2010 - 1 recovery and 3 recovery), respectively.

(4) Net of income tax expense of 6 and 99 for the three and nine months ended Sept. 30, 2011 (2010 - 8 expense and 43 expense), respectively.

(5) Net of income tax of nil and 7 recovery for the three and nine months ended Sept. 30, 2011 (2010 - nil and 11 recovery), respectively.

See accompanying notes.

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

Unaudited	**Sept. 30, 2011**	Dec. 31, 2010	Jan. 1, 2010
Cash and cash equivalents *(Note 10)*	**66**	35	53
Accounts receivable *(Notes 10 and 26)*	**483**	412	405
Current portion of finance lease receivable *(Note 5)*	**3**	2	2
Collateral paid *(Notes 10 and 11)*	**36**	27	27
Prepaid expenses	**18**	10	18
Risk management assets *(Notes 10 and 11)*	**359**	268	146
Income taxes receivable	**-**	18	38
Inventory *(Note 12)*	**99**	53	90
Assets held for sale *(Note 3)*	**3**	60	4
	1,067	885	783
Investments *(Note 6)*	**213**	190	202
Long-term receivable *(Notes 10 and 13)*	**-**	-	49
Finance lease receivable *(Note 5)*	**43**	46	48
Property, plant, and equipment *(Note 14)*			
Cost	**11,380**	11,040	10,831
Accumulated depreciation	**(4,084)**	(3,746)	(3,754)
	7,296	7,294	7,077
Goodwill *(Note 15)*	**447**	447	447
Intangible assets	**279**	288	293
Deferred income tax assets	**182**	178	229
Risk management assets *(Notes 10 and 11)*	**97**	205	222
Other assets *(Note 16)*	**85**	102	103
Total assets	**9,709**	9,635	9,453
Accounts payable and accrued liabilities *(Note 10)*	**448**	482	484
Decommissioning and other provisions *(Note 17)*	**104**	54	61
Collateral received *(Notes 10 and 11)*	**29**	126	86
Risk management liabilities *(Notes 10 and 11)*	**146**	35	45
Income taxes payable	**10**	8	9
Dividends payable *(Notes10, 20 and 21)*	**66**	130	61
Current portion of long-term debt *(Notes 10 and 18)*	**320**	237	9
Liabilities held for sale *(Note 3)*	**3**	3	-
	1,126	1,075	755
Long-term debt *(Notes 10 and 18)*	**3,946**	3,823	4,231
Decommissioning and other provisions *(Note 17)*	**276**	256	287
Deferred income tax liabilities	**506**	538	542
Risk management liabilities *(Notes 10 and 11)*	**119**	123	78
Deferred credits and other long-term liabilities *(Note 19)*	**302**	269	236
Equity			
Common shares *(Note 20)*	**2,256**	2,204	2,164
Preferred shares *(Note 21)*	**293**	293	-
Contributed surplus	**8**	7	5
Retained earnings	**567**	431	495
Accumulated other comprehensive (loss) income *(Note 22)*	**(70)**	185	189
Equity attributable to shareholders	**3,054**	3,120	2,853
Non-controlling interests *(Note 9)*	**380**	431	471
Total equity	**3,434**	3,551	3,324
Total liabilities and equity	**9,709**	9,635	9,453

Contingencies *(Notes 24 and 26)*
Commitments *(Notes 11 and 25)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

9 months ended Sept. 30, 2011

Unaudited	Common shares	Preferred shares	Contributed surplus	Retained earnings	Accumulated other comprehensive income(1)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2010	2,204	293	7	431	185	3,120	431	**3,551**
Net earnings	-	-	-	277	-	277	27	**304**
Other comprehensive income (loss):								
Gains on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	1	1	-	**1**
Net changes in losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(237)	(237)	(4)	**(241)**
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(19)	(19)	-	**(19)**
Total comprehensive income (loss)	-	-	-	277	(255)	22	23	**45**
Common share dividends(2)	-	-	-	(130)	-	(130)	-	**(130)**
Preferred share dividends(3)	-	-	-	(11)	-	(11)	-	**(11)**
Distributions to non-controlling interests	-	-	-	-	-	-	(74)	**(74)**
Common shares issued	52	-	-	-	-	52	-	**52**
Effect of share-based payment plans	-	-	1	-	-	1	-	**1**
Balance, Sept. 30, 2011	**2,256**	**293**	**8**	**567**	**(70)**	**3,054**	**380**	**3,434**

9 months ended Sept. 30, 2010

Unaudited	Common shares	Contributed surplus	Retained earnings	Accumulated other comprehensive income	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	-	-	163	-	163	20	183
Losses on translating net assets of foreign operations, net of hedges and of tax	-			(12)	(12)	-	(12)
Net changes in gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	164	164	(15)	149
Net actuarial losses on defined benefits plans, net of tax	-	-	-	(33)	(33)	-	(33)
Total comprehensive income	-	-	163	119	282	5	287
Common share dividends(4)	-	-	(190)	-	(190)	-	(190)
Distributions to non-controlling interests	-	-	-	-	-	(44)	(44)
Common shares issued	23	-	-	-	23	-	23
Effect of share-based payment plans	-	2	-	-	2	-	2
Balance, Sept. 30, 2010	2,187	7	468	308	2,970	432	3,402

(1) Refer to Note 22 for details on components of, and changes in, Accumulated other comprehensive income.

(2) Represents dividends of $0.58 per share.

(3) Represents dividends of $0.9247 per share.

(4) Represents dividends of $0.87 per share.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Sept. 30		**9 months ended Sept. 30**	
Unaudited	**2011**	2010	**2011**	2010
Operating activities				
Net earnings	**61**	46	**304**	183
Depreciation and amortization *(Note 28)*	**126**	132	**383**	372
Gain on sale of Meridian *(Note 3)*	**-**	-	**(3)**	-
Accretion of provisions *(Note 17)*	**6**	4	**15**	13
Asset retirement costs settled *(Note 17)*	**(7)**	(12)	**(23)**	(27)
Deferred income taxes *(Note 8)*	**5**	3	**79**	28
Unrealized (gain) loss from risk management activities *(Note 11)*	**(13)**	2	**(160)**	2
Unrealized foreign exchange (gain) loss	**(10)**	2	**(8)**	-
Provisions	-	-	**22**	-
Asset impairment charges *(Note 14)*	**5**	-	**14**	-
Equity income, net of distributions from equity investments *(Note 6)*	**(14)**	(11)	**(16)**	(8)
Other non-cash items	**9**	9	**13**	8
	168	175	**620**	571
Change in non-cash operating working capital balances *(Note 29)*	**53**	49	**(108)**	(50)
Cash flow from operating activities	**221**	224	**512**	521
Investing activities				
Additions to property, plant, and equipment *(Notes 14 and 28)*	**(127)**	(193)	**(318)**	(615)
Additions to intangibles *(Note 28)*	**(5)**	(7)	**(16)**	(17)
Proceeds on sale of property, plant, and equipment	**1**	-	**3**	3
Proceeds on sale of Meridian	**-**	-	**30**	-
Resolution of certain tax matters	**-**	12	**3**	12
Realized losses on financial instruments	**(3)**	(1)	**(5)**	(22)
Net (decrease) increase in collateral received from counterparties	**(40)**	60	**(96)**	86
Net decrease (increase) in collateral paid to counterparties	**1**	(4)	**(8)**	(6)
Other	**(19)**	(1)	**(4)**	7
Cash flow used in investing activities	**(192)**	(134)	**(411)**	(552)
Financing activities				
Net increase (decrease) in borrowings under credit facilities *(Note 18)*	**55**	(15)	**355**	(44)
Repayment of long-term debt *(Note 18)*	**(2)**	(2)	**(232)**	(7)
Issuance of long-term debt *(Note 18)*	**-**	-	-	301
Dividends paid on common shares *(Note 20)*	**(48)**	(49)	**(143)**	(169)
Dividends paid on preferred shares *(Note 21)*	**(4)**	-	**(11)**	-
Net proceeds on issuance of common shares *(Note 20)*	**-**	-	**1**	1
Realized gains (losses) on financial instruments	**5**	9	**5**	(8)
Distributions paid to subsidiaries' non-controlling interests *(Note 9)*	**(9)**	(15)	**(44)**	(44)
Reduction of the finance lease receivable *(Note 5)*	**1**	1	**2**	2
Other	**1**	-	**(4)**	-
Cash flow (used in) from financing activities	**(1)**	(71)	**(71)**	32
Cash flow from operating, investing, and financing activities	**28**	19	**30**	1
Effective change in value of foreign cash	**-**	6	**1**	3
Increase in cash and cash equivalents	**28**	25	**31**	4
Cash and cash equivalents, beginning of period	**38**	32	**35**	53
Cash and cash equivalents, end of period	**66**	57	**66**	57
Cash taxes recovered	**(1)**	(37)	**(5)**	(21)
Cash interest paid	**37**	37	**127**	88

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. ACCOUNTING POLICIES

A. Basis of Preparation and Transition to International Financial Reporting Standards

Effective Jan. 1, 2011, all Canadian publicly accountable enterprises are required to prepare their financial statements using International Financial Reporting Standards ("IFRS"), issued by the International Accounting Standards Board, and as adopted by the Accounting Standards Board of Canada. IFRS 1 *First-time Adoption of International Financial Reporting Standards* ("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 have been applied in preparing the condensed consolidated financial statements as at and for the period ended Sept. 30, 2011, the comparative information presented as at and for the periods ended Sept. 30, 2010, Dec. 31, 2010, and in preparation of the opening IFRS Statement of Financial Position as at Jan. 1, 2010.

These condensed consolidated financial statements have been prepared in compliance with *International Accounting Standard 34 Interim Financial Reporting* and *IFRS 1.*

The condensed consolidated financial statements include the accounts of TransAlta Corporation ("TransAlta" or "the Corporation"), and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiary so as to obtain benefits from its activities, generally indicated by ownership of, directly or indirectly, more than one-half of the voting rights.

The condensed consolidated financial statements have been prepared on a historical cost basis, except for financial assets and liabilities that are considered to be held for trading, which are stated at fair value.

These condensed consolidated financial statements were authorized for issue by the Board of Directors on Oct. 27, 2011.

B. Use of Estimates

The preparation of condensed consolidated financial statements in accordance with IFRS requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Refer to Note 1(Y) Critical Accounting Judgments and Key Sources of Estimation Uncertainty for additional information. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

C. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, payments or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be reliably measured. Revenue from the rendering of services are recognized when criteria ii), iii) and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt ("MW") hour produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with lease elements are recognized as outlined in Note 1(T).

Trading activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition of fair value and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in the Condensed Consolidated Statements of Earnings. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Condensed Consolidated Statements of Financial Position as risk management assets or liabilities. Many of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using valuation techniques or models.

D. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint ventures each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar while subsidiary companies and joint ventures' functional currencies are either the Canadian, U.S., or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the condensed consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rate in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the net investment as a result of a disposal, partial disposal, or loss of control.

E. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives, and certain non-financial derivatives, are recognized on the Condensed Consolidated Statements of Financial Position from the point when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: held for trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as held for trading are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are removed from the Condensed Consolidated Statements of Financial Position when the obligation is discharged, cancelled, or expires.

Derivative instruments that are embedded in financial or non-financial contracts are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which are recognized in OCI. Derivatives used in trading activities are described in more detail in Note 1(C).

Transaction costs are expensed as incurred for financial instruments classified or designated as held for trading. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge, or a hedge of foreign currency exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific assets and liabilities on the Condensed Consolidated Statements of Financial Position or to specific firm commitments or anticipated transactions.

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If the above hedge criteria are not met, the derivative is accounted for on the Condensed Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change. For those instruments that the Corporation does not seek, or are ineligible for hedge accounting, changes in fair value are recorded in net earnings.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. Hedge effectiveness for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivatives' cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when it is not probable that the forecasted transaction will occur within the time period specified in the hedge documentation.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, as described above, gains and losses on these derivatives are recognized in net earnings in the same period and financial statement caption as the hedged exposure. Up to the date of settlement, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from anticipated transactions and firm commitments denominated in foreign currencies. If the hedging criteria are met, changes in value are reported in OCI or directly in earnings with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts, and foreign denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from changes in foreign exchange rates. Gains and losses on these instruments that qualify for hedge accounting are reported in OCI with fair values recorded in risk management assets or liabilities.

F. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

G. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

H. Inventory

I. Fuel

The Corporation's inventory balance represents fuel which is measured at the lower of cost and net realizable value. Cost is determined using the weighted average cost method.

The cost of internally produced coal inventory is determined using absorption costing which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower electricity production as maintenance is performed. Due to the limited number of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption.

The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

The majority of fuel and purchased power recognized on the Condensed Consolidated Statements of Earnings reflects the cost of inventory consumed in the generation of electricity.

II. Energy Trading

Commodity inventories held in the Energy Trading segment are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

I. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably.

The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Thermal generation	3-50 years
Gas generation	2-30 years
Renewable generation	3-60 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction (Note 1(U)). Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are amortized over the estimated useful life of the related asset.

J. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition, which is considered to be cost.

Internally-generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale of the intangible asset, and its probable future economic benefits, are demonstrated. Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

Intangible assets acquired separately are recognized at cost.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and accumulated impairment losses, if any.

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangibles may be determined, for example, with reference to the term of the related contract or license agreement. The estimated useful lives and amortization methods are reviewed at each year-end with the effect of any changes being accounted for prospectively.

Intangible assets consist of: power sale contracts, with fixed prices higher than market prices at the date of acquisition; coal rights; and software. Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserve. Estimated useful lives and amortization methods of other intangible assets are as follows:

Software	2-7 years
Power contracts	1-30 years

K. Impairment of Tangible and Intangible Assets excluding Goodwill

At the end of each reporting period the Corporation reviews the net carrying amount of PP&E and finite life intangible assets to determine whether there is any indication that an impairment loss may exist.

Factors which could indicate that an impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner in which an asset is used or in the Corporation's overall business strategy, or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's businesses, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or cash-generating unit, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or cash-generating unit to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the asset's recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

L. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date that control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the cash-generating units to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's cash-generating units that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the cash-generating units to which the goodwill relates is compared to the carrying amount of the cash-generating units. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

M. Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the costs incurred subsequently are included in Other assets or PP&E. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

N. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred tax asset may also be recognized for the benefit expected from unused tax losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred tax is charged or credited to net earnings, except when it related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

O. Employee Future Benefits

The Corporation accrues its obligations under employee future benefit plans and the related costs, net of plan assets. The cost of pension and other post-employment benefits, such as health and dental benefits, earned by employees is actuarially determined using the projected unit credit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. The defined benefit pension plans are based on an employee’s final average earnings and years of service. The expected return on plan assets is based on expected future capital market returns, at the beginning of the period, for returns over the life of the benefit obligations. The discount rate used to determine the present value of the defined benefit obligation is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations.

Actuarial gains and losses arising from experience adjustments and changes in actuarial assumptions are recognized in OCI in the period in which they occur. Past service costs are recognized immediately in net earnings to the extent that the benefits have vested, otherwise, they are amortized on a straight-line basis over the vesting period.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

P. Provisions

A provision is a liability of uncertain timing or amount. Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity’s actions whereby through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, at each period end, of the expenditures required to settle the present obligation considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based discount rate as a cost of the related PP&E (Note 1(I)). The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

Where the Corporation expects to receive reimbursement from a third-party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received.

Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

Q. Share-Based Payments

The Corporation measures equity-settled stock option awards using the fair value method. Compensation expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled share-based payment award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation costs associated with awards under the Performance Share Ownership Plan are accrued based on the fair value of each award, the service period completed, and the number of equivalent common shares eligible employees and directors have earned at the statement of financial position date, which is based upon the percentile ranking of the total shareholder return of the Corporation's common shares in comparison to the total shareholder returns of companies comprising the comparator group.

For share-based payments earned under cash-settled phantom stock option plans, a liability, and corresponding compensation cost, is recognized at each statement of financial position date, until final settlement, based on the fair value of each award and the service period completed.

R. Emission Credits and Allowances

Purchased emission allowances are recorded as assets at cost and are carried at the lower of weighted average cost and net realizable value. Allowances granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, these amounts are recognized as revenue in the period of recovery.

Proprietary trading of emissions allowances that meet the definition of a derivative are accounted for using the fair value method of accounting. Allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

S. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Assets classified as held for sale are reported as current assets in the Condensed Consolidated Statements of Financial Position. Depreciation ceases when an asset is classified as held for sale.

T. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (i.e. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee is recorded in the Condensed Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable, and finance income. The finance income element of the payments is recognized using a method that results in a constant periodic rate of return on the net investment in each period and is reflected in finance lease income on the Condensed Consolidated Statements of Earnings.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is capitalized as PP&E and depreciated over its useful life. Rental income from operating leases is recognized on a straight-line or other appropriate basis over the term of the arrangement and is reflected in Revenue on the Condensed Consolidated Statements of Earnings.

U. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare them for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

V. Non-controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used.

Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains controls.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

W. Joint Ventures

A joint venture is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. Parties to a joint venture recognize their contractual rights and obligations arising from the arrangement. TransAlta's joint ventures are generally classified as two types: jointly controlled assets and jointly controlled entities.

A jointly controlled asset arises when the joint venturers have joint control or joint ownership of one or more assets contributed to, or acquired for and dedicated to, the purpose of the joint venture. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint venture. The Corporation reports its interests in jointly controlled assets by recognizing its share of the assets, its share of the joint venture liabilities and any liabilities it incurs directly, its revenue from the sale of its share of the output of the asset, its share of joint venture expenses, and any expenses it incurs in respect of its interest in the joint venture.

In jointly controlled entities, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer is entitled to a share of the net earnings of the jointly controlled entity. The Corporation reports its interests in jointly controlled entities using the equity method. Under the equity method, the investment in the jointly controlled entity is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the jointly controlled entity's net earnings after the date of acquisition. The Corporation's share of net earnings resulting from transactions between the Corporation and the jointly controlled entities are eliminated based on the Corporation's ownership interest. Distributions received from the jointly controlled entities reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities and contingent liabilities of an acquired jointly controlled entity is recognized as goodwill and is included within the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in jointly controlled entities are evaluated for impairment at each statement of financial position date by first assessing whether there is objective evidence that the investment is impaired. Objective evidence could include, for example, such factors as significant financial difficulty of the investee, or information about significant changes with an adverse effect that have taken place in the technological, market, economic or legal environment in which the investee operates, which may indicate that the cost of the investment may not be recovered. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs to sell.

X. Government Grants

Government grants are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the grant and that the grant will be received. Government grants are recognized in net earnings over the same period in which the related costs or revenues are recognized or as a reduction to the carrying amount of PP&E, if the grants relate to capital items.

Y. Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The application of many of the accounting policies followed by the Corporation involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact the Corporation's condensed consolidated financial statements.

I. Critical Judgments in Applying Accounting Policies

In the process of applying the Corporation's accounting policies, which are described above, management makes judgments that could significantly affect the amounts recognized in the condensed consolidated financial statements. The most critical of these judgments are:

a. Impairment of PP&E

An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist.

Factors which could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the manner in which an asset is used or in the Corporation's overall business strategy, or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence. Management continually monitors the Corporation's businesses, the markets, and the business environment, and make judgments and assessments about conditions and events in order to conclude whether a possible impairment exists.

b. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in evaluating the terms and conditions of these agreements. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These determinations can be significant to the Corporation's financial position and performance as the classification of amounts related to the arrangement as PP&E or as a finance lease receivable, and therefore the determination of certain items of revenue and expense, is dependent upon such determination.

c. Income Taxes

Preparation of the condensed consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Condensed Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced.

Judgment is required in determining the provision for income taxes and deferred income tax assets and liabilities. Management must also exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred income tax assets and liabilities are complete and fairly presented. The effects of differing assessments and applications could be material.

d. Financial Instruments

The fair value of financial instruments are determined and classified within three categories, which are outlined below and discussed in more detail in Note 10.

Level I

Fair values in Level I are determined using inputs that are unadjusted quoted prices in active markets for identical assets or liabilities that the Corporation has the ability to access.

Level II

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

Level III

Fair values in Level III are determined using inputs for the asset or liability that are not readily observable.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. Classification of financial instruments requires management to use judgment in respect of both the determination of fair value and the lowest level input of significance.

e. Project Development Costs

Deferred project developments costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur. Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation.

II. Key Sources of Estimation Uncertainty

The application of certain of the Corporation's accounting policies involves making a number of estimates and assumptions about matters that are highly uncertain at the time the estimate is made. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The resulting key sources of estimation uncertainty are described below:

a. Revenue Recognition - Fair Values of Energy Derivatives

The Corporation's Energy Trading business derives its revenue and earnings primarily from the wholesale trading of electricity and other energy-related commodities and derivatives. These contracts and derivatives are accounted for at fair value, with the initial recognition of fair value and subsequent changes in fair value affecting reported earnings in the period the change occurs. Fair values and changes in such fair values can be favorable or unfavorable, and depending on current market conditions, can fluctuate significantly.

The determination of the fair value of these contracts and derivative instruments is complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. The majority of these derivatives are not traded on an active exchange or in some cases have terms that extend beyond the time period for which exchange-based quotes are available.

Determination of fair value for these derivatives requires the use of internal valuation techniques or models.

b. Valuation of PP&E and Goodwill

PP&E assets are reviewed at the end of each reporting period to determine if an indicator of impairment exists. If indicators of impairment exist for a PP&E asset or cash-generating unit to which a PP&E asset belongs, an estimate of the recoverable amount must be made in order to determine whether an impairment loss is to be recognized.

Goodwill is evaluated for impairment at least annually or more frequently if indicators of impairment exist. To test for impairment, the recoverable amount of the cash-generating units to which the goodwill relates is compared to the carrying amounts of the cash-generating units.

The recoverable amount of a PP&E asset or a cash-generating unit to which goodwill relates is the higher of fair value less costs to sell and value in use. In determining fair value less costs to sell, information about third party transactions for similar assets is used and if none are available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In determining either fair value less costs to sell or value in use using discounted cash flow methods, management must make significant estimates and assumptions about future cash flows, the variability of such cash flows, risks specific to the asset, cash-generating unit, or the Corporation, discount rates and the estimated useful lives of the plants.

In estimating future cash flows of the plants, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management use estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

c. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 1(P) and Note 17. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash flow expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash flow expenditures are present valued using a current, risk adjusted, market-based, pre-tax discount rate. A change in estimated cash flows or market interest rates could have a material impact on the carrying amount of the provision.

d. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

e. Employee Future Benefits

The Corporation provides pension and other post-employment benefits, such as health and dental benefits to employees. The cost of providing these benefits is dependent upon many factors including actual plan experience and estimates and assumptions about future experience.

The liability for post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets;
- the effects of changes to the provisions of the plans; and
- changes in key actuarial assumptions, including anticipated rates of return on plan assets, rates of compensation and health-care cost increases, and discount rates.

A change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for post-employment benefits or the related expense.

Z. Accounting Changes

Current Accounting Changes

I. Change in Estimates – Residual Values

During the first quarter of 2011, management completed a comprehensive review of the residual values of all of TransAlta's generating assets, having regard for, among other things, expectations about the future condition of the assets, metal volumes, as well as other market-related factors. As a result, estimated residual values were revised resulting in depreciation decreasing by $4 million and $10 million for the three and nine months ended Sept. 30, 2011 compared to the same period in 2010. Depreciation for the year ended Dec. 31, 2011 is expected to be lower by approximately $13 million.

Future Accounting Changes

I. IFRS Policies

The interim financial statements as at and for the three and nine months ended Sept. 30, 2011 have been prepared using the standards and interpretations currently issued and expected to be effective at the end of the Corporation's first annual IFRS reporting period, Dec. 31, 2011. Accounting policies currently adopted under IFRS are subject to change as a result of either a new standard being issued with an effective date of Dec. 31, 2011 or prior, or as a result of a voluntary change in accounting policy made by the Corporation during 2011. A change in an accounting policy used may result in material changes to the Corporation's reported financial position, results of operations and cash flows.

II. Consolidated Financial Statements

In May 2011, the International Accounting Standard Board ("IASB") issued IFRS 10 *Consolidated Financial Statements*, which replaces IAS 27 *Consolidated and Separate Financial Statements* and SIC-12 *Consolidation - Special Purpose Entities*. IFRS 10 provides a revised definition of control so that a single control model can be applied to all entities for consolidation purposes.

III. Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements*, which supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principle-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its joint arrangements. IFRS 11 also requires the use of the equity method of accounting for interests in joint ventures. Improvements in disclosure requirements are intended to allow investors to gain a better understanding of the nature, extent and financial effects of the activities that an entity carries out through joint arrangements.

IV. Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in condensed consolidated, and unconsolidated entities, such as subsidiaries, joint arrangements, associates, and unconsolidated structured entities (special purpose entities).

V. Investments in Associates and Joint Ventures and Separate Financial Statements

In May 2011, two existing standards, IAS 28 *Investments in Associates and Joint Ventures,* and IAS 27 *Separate Financial Statements*, were amended. The amendments are not significant, and result from the issuance of IFRS 10, IFRS 11, and IFRS 12.

The requirements of the preceding new standards and amendments to existing standards outlined in points II through V, are effective for annual periods beginning on or after Jan. 1, 2013. The disclosure requirements of IFRS 12 may be incorporated into the financial statements earlier than Jan. 1, 2013. However, early adoption of the other standards is only permitted if all five are applied at the same time. The Corporation is currently assessing the impact of adopting these new standards and amendments on the condensed consolidated financial statements.

VI. Fair Value Measurements

In June 2011, the IASB issued IFRS 13 *Fair Value Measurements*, which establishes a single source of guidance for all fair value measurements required by other IFRS; clarifies the definition of fair value; and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability or its own equity instrument at fair value. IFRS 13 is effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. The Corporation is currently assessing the impact of adopting IFRS 13 on the condensed consolidated financial statements.

VII. Presentation of Financial Statements

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The amendments to IAS 1 are effective for annual periods beginning on or after July 1, 2012. Earlier application is permitted. The Corporation is currently assessing the impact of adopting the amendments to IAS 1 on the condensed consolidated financial statements.

VIII. Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits* to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service cost is presented in net earnings; finance cost is presented as part of finance costs in net earnings; and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI. Amendments eliminate the option to defer the recognition of actuarial gains and losses, known as the 'corridor method'. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. The Corporation is currently assessing the impact of adopting the amendments to IAS 19 on the condensed consolidated financial statements.

IX. Financial Instruments

In November 2009, the IASB issued IFRS 9 *Financial Instruments* which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or fair value through profit or loss or through OCI depending on the basis of the entity's business model for managing the financial asset, and the contractual cash flow characteristics of the financial asset.

In October 2010, the IASB issued additions to IFRS 9 *Financial Instruments* regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

The requirements are effective for annual periods beginning on or after Jan. 1, 2013, and must be applied retrospectively. Earlier adoption is permitted. The IASB has recently issued an Exposure Draft which proposes to postpone the mandatory application of IFRS 9 until 2015. The Corporation is currently assessing the impact of adopting IFRS 9 on the condensed consolidated financial statements.

2. FIRST-TIME ADOPTION OF IFRS

IFRS 1 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 and prior, have been applied in preparing the condensed consolidated financial statements as at and for the period ended Sept. 30, 2011, the comparative information presented as at and for the period ended Sept. 30, 2010, and in preparation of 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.
- The Corporation has 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 Canadian Generally Accepted Accounting Principles ("the Corporation's

previous GAAP"), arrangements reviewed under our previous GAAP have not been reassessed for IFRS transition. TransAlta is required to review arrangements outside of the scope of the Corporation's previous GAAP and have determined that one of the agreements contain a finance lease.

- IFRIC 1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* 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 which had not vested by the Corporation's 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 the Corporation's previous GAAP.
- The Corporation's 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, the Corporation has elected not to do so.
- IAS 23 *Borrowing Costs* 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 the Corporation's 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 the Corporation's previous GAAP was determined following prescribed regulations and has been elected as deemed cost.
- The Corporation has elected to recognize, at the date of transition, all cumulative actuarial gains and losses associated with its defined benefit, pension, and other post-employment benefit plans.

Differences between the Corporation's previous GAAP and its IFRS financial position, its financial performance, and its cash flows, are outlined in the following sections:

A. Reconciliation of Financial Position as at Jan. 1, 2010;
B. Reconciliation of Financial Position as at Sept. 30, 2010;
C. Reconciliation of Financial Position as at Dec. 31, 2010;
D. Reconciliation of Earnings for the three and nine months ended Sept. 30, 2010;
E. Reconciliation of Earnings for the year ended Dec. 31, 2010;
F. Reconciliation of Total Comprehensive Income (Loss) for the three and nine months ended Sept. 30, 2010;
G. Reconciliation of Total Comprehensive Income (Loss) for the year ended Dec. 31, 2010; and
H. Condensed Consolidated Statements of Cash Flow Impact for the three and nine months ended Sept. 30, 2010 and for the year ended Dec. 31, 2010.

A. Reconciliation of Financial Position as at Jan. 1, 2010

TRANSALTA CORPORATION

CONDENSED 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, net	-	-	-	-	-	-	-	-	-	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**
Preferred shares	-	-	-	-	-	-	-	-	-	-	**-**
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**

B. Reconciliation of Financial Position as at Sept. 30, 2010

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(in millions of Canadian dollars)

As at Sept. 30, 2010	Canadian GAAP(1)	IAS 21	IFRS 3	IAS 16	IAS 19	IAS 31	IAS 37	IFRIC 4/ IAS 17	IAS 36	Reclass	IFRS
Cash and cash equivalents	80	-	-	-	-	(23)	-	-	-	-	**57**
Accounts receivable	361	-	-	-	-	(25)	-	-	-	-	**336**
Current portion of finance lease receivable	-	-	-	-	-	-	-	2	-	-	**2**
Collateral paid	32	-	-	-	-	-	-	-	-	-	**32**
Prepaid expenses	27	-	-	-	-	-	-	-	-	-	**27**
Risk management assets	289	-	-	-	-	-	-	-	-	4	**293**
Future income tax assets	-	-	-	-	-	-	-	-	-	-	**-**
Income taxes receivable	53	-	-	-	-	(1)	-	-	-	-	**52**
Restricted cash	7	-	-	-	-	(7)	-	-	-	-	**-**
Inventory	69	-	-	-	-	-	-	-	-	-	**69**
Assets held for sale, net	-	-	-	-	-	-	-	-	-	1	**1**
	918	-	-	-	-	(56)	-	2	-	5	**869**
Investments	-	-	-	-	-	206	-	-	-	-	**206**
Long-term receivables	-	-	-	-	-	-	-	-	-	-	**-**
Finance lease receivable	-	-	-	-	-	-	-	46	-	-	**46**
Property, plant, and equipment											
Cost	11,865	-	(104)	204	-	(374)	43	(55)	(275)	(252)	**11,052**
Accumulated depreciation	(4,076)	-	4	(91)	-	124	(12)	27	197	145	**(3,682)**
	7,789	-	(100)	113	-	(250)	31	(28)	(78)	(107)	**7,370**
Goodwill	432	-	87	-	-	(72)	-	-	-	-	**447**
Intangible assets	311	-	(10)	-	-	(134)	-	-	-	106	**273**
Deferred income tax assets	198	-	-	(5)	8	-	3	-	20	(72)	**152**
Risk management assets	335	-	-	-	-	-	-	-	-	(4)	**331**
Other assets	112	-	-	-	(23)	-	-	-	-	-	**89**
Total assets	10,095	-	(23)	108	(15)	(306)	34	20	(58)	(72)	**9,783**
Accounts payable and accrued liabilities	406	-	2	-	-	(14)	-	-	2	(7)	**389**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	-	46	**46**
Collateral received	169	-	-	-	-	-	-	-	-	-	**169**
Risk management liabilities	30	-	-	-	-	-	-	-	-	6	**36**
Income taxes payable	6	-	-	-	-	(1)	-	-	-	-	**5**
Future income tax liabilities	86	-	-	-	-	-	-	-	-	(86)	**-**
Dividends payable	65	-	-	-	-	-	-	-	-	-	**65**
Current portion of long-term debt	256	-	-	-	-	(21)	-	-	-	-	**235**
Current portion of asset retirement obligations	39	-	-	-	-	-	-	-	-	(39)	**-**
	1,057	-	2	-	-	(36)	-	-	2	(80)	**945**
Long-term debt	4,428	-	-	-	-	(166)	-	-	-	-	**4,262**
Decommissioning and other provisions	-	-	-	-	-	-	-	-	-	284	**284**
Deferred income tax liabilities	655	-	(28)	24	(33)	(87)	(7)	3	(5)	14	**536**
Risk management liabilities	81	-	-	-	-	-	-	-	-	(6)	**75**
Deferred credits and other long-term liabilities	153	-	-	-	131	-	-	-	7	(12)	**279**
Asset retirement obligations	210	-	-	-	-	(5)	67	-	-	(272)	**-**
Non-controlling interests	439	-	-	2	-	(16)	-	10	(3)	(432)	**-**
Equity											
Common shares	2,187	-	-	-	-	-	-	-	-	-	**2,187**
Contributed surplus	7	-	-	-	-	-	-	-	-	-	**7**
Retained earnings	600	(63)	3	82	(80)	4	(26)	7	(59)	-	**468**
Accumulated other comprehensive income	278	63	-	-	(33)	-	-	-	-	-	**308**
Equity attributable to shareholders	3,072	-	3	82	(113)	4	(26)	7	(59)	-	**2,970**
Non-controlling interests	-	-	-	-	-	-	-	-	-	432	**432**
Total equity	3,072	-	3	82	(113)	4	(26)	7	(59)	432	**3,402**
Total liabilities and equity	10,095	-	(23)	108	(15)	(306)	34	20	(58)	(72)	**9,783**

(1) Certain comparative figures have been reclassified to conform to Dec. 31, 2010 presentation. These reclassifications did not impact previously reported net earnings or retained earnings.

C. Reconciliation of Financial Position as at Dec. 31, 2010

TRANSALTA CORPORATION

CONDENSED 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, net	-	-	-	-	-	-	-	-	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 the Corporation's previous GAAP to IFRS related to the Condensed Consolidated Statements of Financial Position as at Jan.1, 2010, Sept. 30, 2010, and Dec. 31, 2010 in the above-noted tables are as follows:

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

Retrospective application of IAS 21 *The Effects of Changes in Foreign Exchange Rates* 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 in accordance with the Corporation's accounting policy outlined in Note 1(D).

II. 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. The Corporation's 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 Developers, Inc. ("Canadian Hydro") purchase price.

III. 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 the Corporation's 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.

IV. IAS 19 *Employee Benefits*

Under the Corporation's 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 in accordance with the Corporation's accounting policy outlined in Note 1(O).

V. IAS 31 *Interests in Joint Ventures*

Under the Corporation's 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. TransAlta's 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 the Corporation's 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. TransAlta accounts for its interest in jointly controlled entities using the equity method. Under the equity method, TransAlta's investments in its CE Generation LLC ("CE Gen") and Wailuku River Hydroelectric L.P. ("Wailuku") jointly controlled entities is reflected as a single line item, entitled "Investments", on the Condensed Consolidated Statements of Financial Position, and the Corporation's share of the income is reflected as equity earnings or loss in the Condensed Consolidated Statements of Earnings. TransAlta's 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 Condensed 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.

VI. 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 discount rate, where applicable. The Corporation's previous GAAP did not require consideration of changes in the market-based discount rate at each period end. The Corporation's 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 *Changes in Existing Decommissioning, Restoration and Similar Liabilities*, 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 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 the Corporation to reconstruct a historical record of all such adjustments that would have been made in the past. Use of the IFRS 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, using the IFRS depreciation policies outlined in Note 1(I).

VII. 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 the Corporation's 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:

a. Finance leases

Where the Corporation determines 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 the Corporation's PP&E and the amounts due from the lessees under the related finance leases recorded in the Condensed 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.

b. Operating leases

Where the Corporation determines 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 the Corporation's previous GAAP.

VIII. IAS 36 *Impairment of Assets*

Under IAS 36, undiscounted future cash flows are not used to initially assess for impairment, as under the Corporation's 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, impairment losses were recognized on certain Generation assets and a provision was recognized for an onerous contract. Due to IFRS transition impairments, the timing of recognition of impairment losses differed under IFRS versus the Corporation's previous GAAP.

In preparing its IFRS opening Statement of Financial Position, the Corporation recognized pre-tax impairment losses of $101 million ($98 million after deducting the amount that is attributable to the non-controlling interest) which 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 one of the Corporation's contracted facilities. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and is primarily due to the Corporation's shift in managing the coal-fired generation facilities on a unit pair basis. The recoverable amounts of impaired assets were based on fair value derived through the use of discounted cash flow analysis from the Corporation's long-range forecasts and other market-based assumptions, as considered appropriate.

IX. IFRS Reclassifications

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

D. Reconciliation of Earnings for the three and nine months ended Sept. 30, 2010

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF EARNINGS

(in millions of Canadian dollars)

For the 3 months ended Sept. 30, 2010	Canadian GAAP[1]	IFRS 3	IAS 16	IAS 19	IAS 31[2]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Revenues	700	-	-	-	(46)	-	(3)	-	**651**
Fuel and purchased power	320	-	-	-	(4)	-	-	(1)	**315**
	380	-	-	-	(42)	-	(3)	1	**336**
Operations, maintenance, and administration	149	-	(18)	1	(13)	-	-	-	**119**
Depreciation and amortization	126	(1)	20	-	(12)	(4)	(1)	(3)	**125**
Taxes, other than income taxes	7	-	-	-	-	-	-	-	**7**
	282	(1)	2	1	(25)	(4)	(1)	(3)	**251**
	98	1	(2)	(1)	(17)	4	(2)	4	**85**
Finance lease income	-	-	-	-	-	-	2	-	**2**
Equity income	-	-	-	-	11	-	-	-	**11**
Foreign exchange gain	1	-	-	-	-	-	-	-	**1**
Net interest expense	(49)	-	-	-	4	(4)	-	-	**(49)**
Earnings (loss) before income taxes	50	1	(2)	(1)	(2)	-	-	4	**50**
Income tax expense (recovery)	4	1	-	(1)	(2)	-	-	2	**4**
Net earnings (loss)	46	-	(2)	-	-	-	-	2	**46**

(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 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

For the 9 months ended Sept. 30, 2010	Canadian GAAP[1]	IFRS 3	IAS 16	IAS 19	IAS 31[2]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
Revenues	2,008	-	-	-	(106)	-	(8)	-	**1,894**
Fuel and purchased power	871	-	-	-	(9)	(2)	-	(3)	**857**
	1,137	-	-	-	(97)	2	(8)	3	**1,037**
Operations, maintenance, and administration	481	-	(57)	3	(46)	-	-	-	**381**
Depreciation and amortization	348	(3)	59	-	(37)	(11)	(2)	(7)	**347**
Taxes, other than income taxes	21	-	-	-	-	-	-	-	**21**
	850	(3)	2	3	(83)	(11)	(2)	(7)	**749**
	287	3	(2)	(3)	(14)	13	(6)	10	**288**
Finance lease income	-	-	-	-	-	-	6	-	**6**
Equity income	-	-	-	-	8	-	-	-	**8**
Foreign exchange gain	4	-	-	-	-	-	-	-	**4**
Asset impairment charges	-	-	-	-	-	-	-	-	**-**
Net interest expense	(130)	-	-	-	13	(13)	-	-	**(130)**
Earnings (loss) before income taxes	161	3	(2)	(3)	7	-	-	10	**176**
Income tax (recovery) expense	(15)	1	-	(1)	4	-	-	4	**(7)**
Net earnings (loss)	176	2	(2)	(2)	3	-	-	6	**183**

(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 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

E. Reconciliation of Earnings for the year ended Dec. 31, 2010

TRANSALTA CORPORATION

CONDENSED 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	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 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 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

Explanations of the adjustments from the Corporation's previous GAAP to IFRS related to the Condensed Consolidated Statements of Earnings for the three and nine months ended Sept. 30, 2010 and for the year ended Dec. 31, 2010 are as follows:

I. 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 the Corporation's previous GAAP.

II. IFRS 3 *Business Combinations*

IFRS 3 requires subsequent adjustments to the provisional purchase price allocation amounts recognized at the acquisition date to be reflected retrospectively as at the acquisition date, whereas the Corporation's previous GAAP requires prospective application. As a result, depreciation and amortization recognized in 2010 under the Corporation's previous GAAP, was recognized as a transition date adjustment under IFRS.

III. 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 the Corporation's previous GAAP. The adjustment represents the capitalization of expenditures incurred in the period that were expensed under the Corporation's previous GAAP and the depreciation of expenditures capitalized on transition to IFRS.

IV. 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 the Corporation's previous GAAP amounts.

V. IAS 31 *Interests in Joint Ventures*

Under the Corporation's 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. The Corporation has adopted the equity method for its interests in the CE Gen and Wailuku jointly controlled entities. The adjustment represents the reclassification of the Corporation's proportionate share of CE Gen and Wailuku's revenue and expenses from each respective line item to a single line item entitled "Equity loss".

VI. IAS 37 *Provisions*

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

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

Under IFRS, the Corporation's Fort Saskatchewan long-term contract is considered a finance lease arrangement. The adjustment represents the reversal of i) revenues recognized under the Corporation's 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.

VIII. 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 the Corporation's 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.

F. Reconciliation of Total Comprehensive Income (Loss) for the three and nine months ended Sept. 30, 2010

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

For the 3 months ended Sept. 30, 2010	Canadian GAAP[1]	IFRS 3	IAS 16	IAS 19	IAS 31	IAS 37	IAS 36	IFRS
Net earnings (loss)	46	-	(2)	-	-	-	2	**46**
Losses on translating net assets of foreign operations	(14)	-	-	-	-	-	-	**(14)**
Gains on financial instruments designated as hedges of foreign operations, net of tax	8	-	-	-	-	-	-	**8**
Gains on derivatives designated as cash flow hedges, net of tax	107	-	-	-	-	-	-	**107**
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax	1	-	-	-	-	-	-	**1**
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax	(11)	-	-	-	-	-	-	**(11)**
Net actuarial losses on defined benefit plans, net of tax	-	-	-	1	-	-	-	**1**
Other comprehensive income	91	-	-	1	-	-	-	**92**
Total comprehensive income (loss)	137	-	(2)	1	-	-	2	**138**
Total comprehensive income (loss) attributable to:								
Common shareholders	144	-	-	1	-	-	2	**147**
Non-controlling interests	(7)	-	(2)	-	-	-	-	**(9)**
	137	-	(2)	1	-	-	2	**138**

(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.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

For the 9 months ended Sept. 30, 2010	Canadian GAAP(1)	IFRS 3	IAS 16	IAS 19	IAS 31(2)	IAS 37	IAS 36	IFRS
Net earnings (loss)	176	2	(2)	(2)	3	-	6	**183**
(Losses) gains on translating net assets of foreign operations	(22)	-	-	-	-	-	-	**(22)**
Gains on financial instruments designated as hedges of foreign operations, net of tax	10	-	-	-	-	-	-	**10**
Gains on derivatives designated as cash flow hedges, net of tax	224	-	-	-	-	-	-	**224**
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	(83)	-	-	-	-	-	-	**(83)**
Net actuarial losses on defined benefit plans, net of tax	-	-	-	(33)	-	-	-	**(33)**
Other comprehensive income (loss)	137	-	-	(33)	-	-	-	**104**
Total comprehensive income (loss)	313	2	(2)	(35)	3	-	6	**287**
Total comprehensive income (loss) attributable to:								
Common shareholders	308	2	(2)	(35)	3	-	6	**282**
Non-controlling interests	5	-	-	-	-	-	-	**5**
	313	2	(2)	(35)	3	-	6	**287**

(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 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

Explanation of the adjustments from the Corporation's previous GAAP to IFRS related to the Condensed Consolidated Statement of Comprehensive Income (Loss) for the three and nine months ended Sept. 30, 2010 are as follows:

I. IAS 19 *Employee Benefits*

Under IFRS, the Corporation's policy is to recognize actuarial gains and losses in OCI in the period in which they occur. Under the Corporation's 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.

II. 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.

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

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(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**
(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**
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)**
Reclassification of gains on translation of foreign operations to net earnings, net of tax	(2)	(1)	-	-	-	-	-	-	-	**(3)**
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 Condensed 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 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

Explanations of the adjustments from the Corporation's previous GAAP to IFRS related to the Condensed Consolidated Statements of Comprehensive Income (Loss) for the year ended Dec. 31, 2010 are as follows:

I. 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 the Corporation's previous GAAP.

II. IAS 19 *Employee Benefits*

Under IFRS, the Corporation's policy is to recognize actuarial gains and losses in OCI in the period in which they occur. Under the Corporation's 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.

III. 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.

H. Condensed Consolidated Statements of Cash Flow Impact:

The transition to IFRS changed the presentation of several items on the Condensed Consolidated Statements of Cash Flows. The most significant of these changes is the effects of applying the equity method of accounting to the Corporation's interest in jointly controlled entities, versus the proportionate consolidation method used under the Corporation's previous GAAP. TransAlta's 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 Condensed Consolidated Statements 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 previously expensed under the Corporation's previous GAAP will result in these cash expenditures being reported as an investing activity under IFRS. Under the Corporation's previous GAAP these expenditures impacted cash flow from operations.

3. DISPOSITIONS

During the third quarter of 2011, the Corporation signed an agreement to sell its biomass facility located in Grande Prairie. The sale was effective Sept.1, 2011 and closed on Oct. 1, 2011. As a result, all associated assets and liabilities, which are included in the Generation segment, have been classified as held for sale as at Sept. 30, 2011.

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, all associated assets and liabilities have been classified as held for sale under the Generation segment. The sale was effective Jan. 1, 2011 and was closed on April 1, 2011. As a result, the Corporation realized a pre-tax gain of $3 million during the nine months ended Sept. 30, 2011.

4. EXPENSES BY NATURE

Expenses classified by nature are as follows:

	3 months ended Sept. 30, 2011		3 months ended Sept. 30, 2010	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**188**	**-**	249	-
Purchased power	**59**	**-**	58	-
Salaries and benefits	**1**	**77**	1	63
Depreciation	**10**	**-**	7	-
Other operating expenses	**-**	**61**	-	56
Total	**258**	**138**	315	119

	9 months ended Sept. 30, 2011		9 months ended Sept. 30, 2010	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**495**	**-**	653	-
Purchased power	**127**	**-**	176	-
Salaries and benefits	**4**	**215**	3	204
Depreciation	**29**	**-**	25	-
Other operating expenses	**-**	**185**	-	177
Total	**655**	**400**	857	381

5. LEASES

A. The Corporation as Lessor

I. Finance Leases

The amounts receivable under finance leases are as follows:

As at	**Sept. 30, 2011**		Dec. 31, 2010	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**10**	**9**	10	9
Second to fifth years inclusive	**41**	**25**	41	25
More than five years	**34**	**12**	42	14
	85	**46**	93	48
Less: unearned finance income	**39**	**-**	45	-
Total finance lease receivable	**46**	**46**	48	48

Included in the Condensed Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables	**3**	2
Non-current finance lease receivables	**43**	46
	46	48

As at	Jan. 1, 2010	
	Minimum lease payments	Present value of minimum lease payments
Within one year	10	9
Second to fifth years inclusive	41	25
More than five years	52	16
	103	50
Less: unearned finance income	53	-
Total finance lease receivable	50	50

Included in the Condensed Consolidated Statements of Financial Position as:	
Current portion of finance lease receivables	2
Non-current finance lease receivables	48
	50

The interest rate inherent in the lease is fixed at the contract date for the entire lease term and is approximately 17 per cent per annum.

II. Operating Leases

For arrangements considered to be operating leases, total contingent rents recognized as revenue in the Condensed Consolidated Statements of Earnings for the three and nine months ended Sept. 30, 2011 was $44 million (Sept. 30, 2010 - $66 million), and $145 million (Sept. 30, 2010 - $199 million), respectively.

B. The Corporation as Lessee

I. Operating Leases

The Corporation has entered into operating leases for equipment used for operating and administration purposes. During the three and nine months ended Sept. 30, 2011, $3 million (Sept. 30, 2010 - $2 million), and $9 million (Sept. 30, 2010 - $6 million), respectively, was recognized as an expense in the Condensed Consolidated Statements of Earnings in respect of these operating leases. No sublease payments were received or made, nor were any contingent rental payments made, in respect of these operating leases.

Future minimum lease payments required under non-cancellable operating leases are as follows:

2011	5
2012	13
2013	12
2014	11
2015	10
2016 and thereafter	52
Total minimum lease payments	**103**

6. INVESTMENTS

The Corporation’s investment in jointly controlled entities accounted for using the equity method consists mainly of its investment in CE Gen.

The change in investments is as follows:

Balance, Dec. 31, 2010	190
Equity income	16
Change in foreign exchange rates	7
Balance, Sept. 30, 2011	**213**

Balance, Jan. 1, 2010	202
Equity income	8
Change in foreign exchange rates	(4)
Balance, Sept. 30, 2010	206

Summarized information on the results of operations and financial position relating to the Corporation's pro-rata interests in its jointly controlled entities is as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2011	2010	**2011**	2010
Results of operations				
Revenues	**45**	46	**104**	106
Expenses, including interest	**(31)**	(35)	**(88)**	(98)
Proportionate share of net income	**14**	11	**16**	8

Summarized information on the financial position relating to the Corporation's pro-rata interests in its jointly controlled entities is as follows:

As at	**Sept. 30, 2011**	Dec. 31, 2010	Jan. 1, 2010
Financial position			
Current assets	**61**	42	48
Long-term assets	**439**	437	486
Current liabilities	**(32)**	(28)	(36)
Long-term liabilities	**(241)**	(246)	(280)
Non-controlling interests	**(14)**	(15)	(16)
Proportionate share of net assets	**213**	190	202

7. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Interest on debt	**57**	60	**167**	168
Interest income	**-**	(2)	**-**	(16)
Capitalized interest	**(8)**	(13)	**(31)**	(35)
Ineffectiveness on fair value hedges	**(1)**	-	**(1)**	-
Other	**-**	-	**1**	-
Interest expense	**48**	45	**136**	117
Accretion of provisions *(Note 17)*	**6**	4	**15**	13
Net interest expense	**54**	49	**151**	130

The Corporation capitalizes interest during the construction phase of growth capital projects. The Capitalized interest in 2011 relates primarily to Keephills Unit 3. Capitalized interest in 2010 relates primarily to Keephills Unit 3, Summerview 2, Ardenville, and Kent Hills 2.

8. INCOME TAXES

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Current tax expense (recovery)	**4**	1	**16**	(5)
Adjustments in respect of current income tax of previous year	**-**	-	**-**	(30)
Deferred income tax expense related to the origination and reversal of temporary differences	**5**	3	**79**	28
Income tax expense (recovery)	**9**	4	**95**	(7)

Presented in the Condensed Consolidated Statements of Earnings as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2011	2010	**2011**	2010
Current tax expense (recovery)	**4**	1	**16**	(35)
Deferred income tax expense	**5**	3	**79**	28
Income tax expense (recovery)	**9**	4	**95**	(7)

9. NON-CONTROLLING INTERESTS

The change in non-controlling interests is as follows:

Balance, Dec. 31, 2010	431
Distributions paid	(74)
Non-controlling interests' portion of net earnings	27
Non-controlling interests' portion of OCI	(4)
Balance, Sept. 30, 2011	**380**

Balance, Jan. 1, 2010	471
Distributions paid	(44)
Non-controlling interests' portion of net earnings	20
Non-controlling interests' portion of OCI	(15)
Balance, Sept. 30, 2010	432

10. FINANCIAL INSTRUMENTS

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost (Note 1(E)). The following table highlights the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Sept. 30, 2011

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	66	-	66
Accounts receivable	-	-	483	-	483
Collateral paid	-	-	36	-	36
Risk management assets					
Current	8	351	-	-	359
Long-term	34	63	-	-	97
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	448	448
Collateral received	-	-	-	29	29
Dividends payable	-	-	-	66	66
Risk management liabilities					
Current	32	114	-	-	146
Long-term	111	8	-	-	119
Long-term debt(1)	-	-	-	4,266	4,266

(1) Includes current portion.

Carrying value of financial instruments as at Dec. 31, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	35	-	35
Accounts receivable	-	-	412	-	412
Collateral paid	-	-	27	-	27
Risk management assets					
Current	186	82	-	-	268
Long-term	204	1	-	-	205
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	482	482
Collateral received	-	-	-	126	126
Dividends payable	-	-	-	130	130
Risk management liabilities					
Current	5	30	-	-	35
Long-term	123	-	-	-	123
Long-term debt(1)	-	-	-	4,060	4,060

(1) Includes current portion.

Carrying value of financial instruments as at Jan. 1, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	53	-	53
Accounts receivable	-	-	405	-	405
Collateral paid	-	-	27	-	27
Risk management assets					
Current	130	16	-	-	146
Long-term	219	3	-	-	222
Long-term receivable	-	-	49	-	49
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	484	484
Collateral received	-	-	-	86	86
Dividends payable	-	-	-	61	61
Risk management liabilities					
Current	28	17	-	-	45
Long-term	75	3	-	-	78
Long-term debt(1)	-	-	-	4,240	4,240

(1) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. In limited circumstances, the Corporation uses inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below:

Level I

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

Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

Level III

Fair values are determined using inputs for the asset or liability that are not readily observable.

The Corporation may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally-developed fundamental price forecast is used in the valuation.

TransAlta also has various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with counterparties that the Corporation believes to be creditworthy.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments in relation to trading activities and certain contracting activities.

The following table summarizes the key factors impacting the fair value of the energy trading risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2011:

	Hedges			Non-hedges			Total		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets (liabilities) at Dec. 31, 2010	-	319	(20)	(1)	53	-	(1)	372	(20)
Changes attributable to:									
Market price changes on existing contracts	-	6	(23)	(5)	(18)	22	(5)	(12)	(1)
Market price changes on new contracts	-	8	-	4	50	6	4	58	6
Contracts settled	-	(146)	-	1	(46)	1	1	(192)	1
Discontinued hedge accounting on certain contracts	-	(253)	30	-	253	(30)	-	-	-
Net risk management assets (liabilities) at Sept. 30, 2011	**-**	**(66)**	**(13)**	**(1)**	**292**	**(1)**	**(1)**	**226**	**(14)**
Additional Level III gain information:									
Change in fair value included in OCI			(23)			-			(23)
Realized loss included in earnings before income taxes			-			(1)			(1)
Unrealized gain included in earnings before income taxes relating to net assets held at Sept. 30, 2011			-			35			35

To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of the Energy Trading and Generation business segments.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at Sept. 30, 2011 is estimated to be +/- $28 million (Dec. 31, 2010 - $14 million, Jan. 1, 2010 - $24 million). Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

The total change in Level III financial assets and liabilities held at Sept. 30, 2011 that was recognized in pre-tax earnings for the nine months ended Sept. 30, 2011 was a $34 million gain (Sept. 30, 2010 - $2 million).

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	-
	Level II	(7)	(7)	(19)	(16)	(8)	(9)	(66)
	Level III	(3)	(5)	(5)	-	-	-	(13)
Non-hedges	Level I	(2)	(1)	2	-	-	-	(1)
	Level II	53	180	44	17	(1)	(1)	292
	Level III	6	13	4	1	(2)	(23)	(1)
Total by level	Level I	(2)	(1)	2	-	-	-	(1)
	Level II	46	173	25	1	(9)	(10)	226
	Level III	3	8	(1)	1	(2)	(23)	(14)
Total net assets (liabilities)		**47**	**180**	**26**	**2**	**(11)**	**(33)**	**211**

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt, and the net investment in self-sustaining foreign subsidiaries.

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2011:

	Hedges			**Non-hedges**			**Total**		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets (liabilities) at Dec. 31, 2010	-	(37)	-	-	1	-	-	(36)	-
Changes attributable to:									
Market price changes on existing contracts	-	43	-	-	-	-	-	43	-
Market price changes on new contracts	-	(27)	-	-	1	-	-	(26)	-
Contracts settled	-	(1)	-	-	-	-	-	(1)	-
Net risk management assets (liabilities) at Sept. 30, 2011	**-**	**(22)**	**-**	**-**	**2**	**-**	**-**	**(20)**	**-**

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	(6)	(2)	-	(1)	(15)	2	**(22)**
	Level III	-	-	-	-	-	-	**-**
Non-hedges	Level I	-	-	-	-	-	-	**-**
	Level II	2	-	-	-	-	-	**2**
	Level III	-	-	-	-	-	-	**-**
Total by level	Level I	-	-	-	-	-	-	**-**
	Level II	(4)	(2)	-	(1)	(15)	2	**(20)**
	Level III	-	-	-	-	-	-	**-**
Total net assets (liabilities)		**(4)**	**(2)**	**-**	**(1)**	**(15)**	**2**	**(20)**

	Fair value(1)				Total carrying
As at Sept. 30, 2011	**Level I**	**Level II**	**Level III**	**Total**	**value**
Financial assets and liabilities measured at other than fair value					
Long-term debt - Sept. 30, 2011(2)	**-**	**4,568**	**-**	**4,568**	**4,266**
Long-term debt - Dec. 31, 2010(2)	-	4,279	-	4,279	4,060
Long-term debt - Jan. 1, 2010(2)	-	4,303	-	4,303	4,240

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, collateral paid, long-term receivable, accounts payable and accrued liabilities, collateral received, and dividends payable).

(2) Includes current portion.

C. Inception Gains and Losses

The fair values of the majority of derivatives traded by the Corporation are determined, directly or indirectly, using inputs that are observable for the asset or liability.

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Condensed Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the period is as follows:

As at	**Sept. 30, 2011**	Dec. 31, 2010	Jan. 1, 2010
Unamortized gain (loss) at beginning of period	**1**	(1)	2
New inception (losses) gains	**(4)**	3	(1)
Amortization recorded in net earnings during the period	**5**	(1)	(2)
Unamortized gain (loss) at end of period	**2**	1	(1)

11. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	Sept. 30, 2011					Dec. 31, 2010	Jan. 1, 2010
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total	Total
Risk management assets							
Energy trading							
Current	-	3	-	346	349	264	146
Long-term	-	3	-	63	66	186	205
Total energy trading risk management assets	-	6	-	409	415	450	351
Other							
Current	5	-	-	5	10	4	-
Long-term	-	2	29	-	31	19	17
Total other risk management assets	5	2	29	5	41	23	17
Risk management liabilities							
Energy trading							
Current	-	19	-	111	130	30	30
Long-term	-	66	-	8	74	69	50
Total energy trading risk management liabilities	-	85	-	119	204	99	80
Other							
Current	11	2	-	3	16	5	15
Long-term	-	45	-	-	45	54	28
Total other risk management liabilities	11	47	-	3	61	59	43
Net energy trading risk management assets (liabilities)	**-**	**(79)**	**-**	**290**	**211**	**351**	**271**
Net other risk management assets (liabilities)	**(6)**	**(45)**	**29**	**2**	**(20)**	**(36)**	**(26)**
Net total risk management assets (liabilities)	**(6)**	**(124)**	**29**	**292**	**191**	**315**	**245**

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (Dec. 31, 2010 - U.S.$820 million, Jan. 1, 2010 - U.S.$1,100 million), and borrowings under a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2010 - U.S.$300 million, Jan. 1, 2010 - U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in foreign operations.

The Corporation has also hedged a portion of its net investment in foreign operations with cross-currency interest rate swaps and foreign currency forward sales contracts as shown below:

Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap used as part of the net investment hedge is as follows:

As at	**Sept. 30, 2011**		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value asset (liability)**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value liability	Maturity
-	**-**	**-**	-	-	-	AUD34	(2)	2010

Foreign Currency Contracts

Outstanding foreign currency forward sale contracts used as part of the net investment hedge are as follows:

As at	**Sept. 30, 2011**		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value asset (liability)**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value liability	Maturity
AUD210	**1**	**2011-2012**	AUD180	(1)	2011	AUD120	(2)	2010
U.S.180	**(7)**	**2011-2012**	U.S.120	1	2011	**-**	**-**	**-**

ii. Effect on the Condensed Consolidated Statements of Comprehensive Income

For the three months ended Sept. 30, 2011, a net after-tax gain of $19 million (Sept. 30, 2010 – loss of $6 million) related to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI. For the nine months ended Sept. 30, 2011, a net after-tax gain of $1 million (Sept. 30, 2010 – loss of $12 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the pre-tax impact of net investment hedges on the Condensed Consolidated Statements of Comprehensive Income:

Financial instruments in net investment hedging relationships	**Pre-tax loss recognized in OCI for the 3 months ended Sept. 30, 2011**	Pre-tax gain (loss) recognized in OCI for the 3 months ended Sept. 30, 2010
Long-term debt	**(71)**	26
Cross currency	**-**	-
Foreign exchange	**(7)**	(16)
OCI impact	**(78)**	10

Financial instruments in net investment hedging relationships	**Pre-tax loss recognized in OCI for the 9 months ended Sept. 30, 2011**	Pre-tax gain (loss) recognized in OCI for the 9 months ended Sept. 30, 2010
Long-term debt	**(37)**	35
Cross currency	**-**	3
Foreign exchange	**(11)**	(26)
OCI impact	**(48)**	12

b. Cash Flow Hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at Sept. 30, 2011, were as follows:

(Thousands)	Sept. 30, 2011		Dec. 31, 2010		Jan. 1, 2010	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**8,538**	**6**	28,814	10	28,989	-
Natural gas (GJ)	**2,416**	**38,921**	1,925	32,751	2,163	360
Oil (gallons)	**-**	**4,368**	-	12,432	-	25,074

During the three and nine months ended Sept. 30, 2011, unrealized pre-tax gains of $3 million and $207 million, respectively, were released from AOCI and recognized in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices which will change between now and the time the underlying hedged transactions are expected to occur. 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, the majority of which will occur during 2011 and 2012. 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.

The Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Sept. 30, 2011, cumulative gains of $95 million, $78 million of which was discontinued in the third quarter of 2011, will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur.

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Receipts and Expenditures

The Corporation uses forward foreign exchange contracts to hedge a portion of its future foreign denominated receipts and expenditures as follows:

As at	Sept. 30, 2011			Dec. 31, 2010			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
250	**U.S.233**	**(6)**	**2011-2017**	217	U.S.200	(11)	2011-2017
U.S.10	**10**	**-**	**2011-2012**	U.S.8	8	-	2011
103	**EURO 74**	**-**	**2012**	-	-	-	-

As at	Jan. 1, 2010			
	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
	91	U.S.78	(8)	2010
	U.S.14	15	-	2010
	AUD4	U.S.3	-	2010

Foreign Exchange Forward Contracts on Foreign Denominated Debt

Outstanding foreign exchange forward purchase contracts used to manage foreign exchange exposure on debt not designated as a net investment hedge are as follows:

As at	Sept. 30, 2011		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset (liability)	Maturity
U.S.300	**(1)**	**2012**	U.S.300	(7)	2012	-	-	-
U.S.300	**(2)**	**2013**	U.S.300	(7)	2013	-	-	-

Cross-Currency Interest Rate Swap

TransAlta uses cross-currency interest rate swaps to manage foreign exchange risk exposures on foreign denominated debt as follows:

As at	Sept. 30, 2011		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.500	**(15)**	**2015**	U.S.500	(27)	2015	U.S.500	(16)	2015

iii. Interest Rate Risk Management

The Corporation has outstanding forward start interest rate swaps with fixed rates ranging from 2.75 per cent to 3.43 per cent.

As at	Sept. 30, 2011		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value liability	Maturity
U.S.300	**(21)**	**2012**	-	-	-	-	-	-
-	-	-	-	-	-	U.S.300(1)	(8)	2010

(1) These swaps were closed out upon the issuance of the U.S. $300 million senior notes during the first quarter of 2010 and the resulting losses have been included in AOCI and will be amortized to earnings over the original 10-year term of the swaps.

iv. Effect on the Condensed Consolidated Statements of Comprehensive Income

Forward sale and purchase commodity contracts, foreign exchange contracts, cross-currency interest rate swaps, as well as interest rate contracts, are used to hedge the variability in future cash flows. All components of each derivative's change in fair value have been included in the assessment of cash flow hedge effectiveness.

The following tables summarize the impact of cash flow hedges on the Condensed Consolidated Statements of Comprehensive Income, Condensed Consolidated Statements of Earnings, and the Condensed Consolidated Statements of Financial Position:

3 months ended Sept. 30, 2011

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity	**(29)**	Revenue	**12**	Revenue	**(3)**
Foreign exchange gain on project hedges	**11**	Property, plant, and equipment	**-**	Foreign exchange (gain) loss	**-**
Foreign exchange gain on U.S. debt	**31**	Foreign exchange (gain) loss	**(69)**	Foreign exchange (gain) loss	**-**
Cross-currency interest rate swaps	**28**	Foreign exchange (gain) loss	**-**	Foreign exchange (gain) loss	**-**
Interest rate	**(21)**	Interest expense	**-**	Interest expense	**-**
OCI impact	**20**	**OCI impact**	**(57)**	**Net earnings impact**	**(3)**

3 months ended Sept. 30, 2010

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity	197	Revenue	(46)	Revenue	-
Foreign exchange gain (loss) on project hedges	(6)	Property, plant, and equipment	2	Foreign exchange (gain) loss	-
Foreign exchange gain (loss) on U.S debt	(10)	Foreign exchange (gain) loss	26	Foreign exchange (gain) loss	-
Cross-currency interest rate swaps	(10)	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Interest rate	-	Interest expense	1	Interest expense	-
OCI impact	171	OCI impact	(17)	Net earnings impact	-

9 months ended Sept. 30, 2011

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity	**(45)**	Revenue	**(60)**	Revenue	**(207)**
Foreign exchange gain on project hedges	**6**	Property, plant, and equipment	**-**	Foreign exchange (gain) loss	**-**
Foreign exchange gain on U.S. debt	**12**	Foreign exchange (gain) loss	**-**	Foreign exchange (gain) loss	**-**
Cross-currency interest rate swaps	**14**	Foreign exchange (gain) loss	**(36)**	Foreign exchange (gain) loss	**-**
Interest rate	**(21)**	Interest expense	**1**	Interest expense	**-**
OCI impact	**(34)**	**OCI impact**	**(95)**	**Net earnings impact**	**(207)**

9 months ended Sept. 30, 2010

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity	357	Revenue	(134)	Revenue	-
Foreign exchange gain (loss) on project hedges	(7)	Property, plant, and equipment	11	Foreign exchange (gain) loss	-
Foreign exchange gain (loss) on U.S debt	-	Foreign exchange (gain) loss	7	Foreign exchange (gain) loss	-
Cross-currency interest rate swaps	7	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Interest rate	(9)	Interest expense	1	Interest expense	-
OCI impact	348	OCI impact	(115)	Net earnings impact	-

Over the next 12 months, the Corporation estimates that $40 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. In addition, it is the Corporation's intent to settle a substantial portion of the cash flow hedges by physical delivery of the underlying commodity, resulting in gross settlement at the contract price.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 5.75 per cent to 6.65 per cent, to floating rate debt through interest rate swaps as shown below:

As at	**Sept. 30, 2011**		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset (liability)	Maturity
-	**-**	**-**	100	2	2011	100	7	2011
U.S.100	**3**	**2013**	U.S.100	3	2013	U.S.50	(1)	2013
U.S.150	**26**	**2018**	U.S.200	16	2018	U.S.100	7	2018

Including the interest rate swaps above, 30 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2010 - 25 per cent, Jan. 1, 2010 - 31 per cent).

ii. Effect on the Condensed Consolidated Statements of Comprehensive Income

The following table summarizes the impact and location of the ineffective portion of fair value hedges on the Condensed Consolidated Statements of Earnings:

Derivatives in fair value hedging relationships	**Location of (loss) gain on Consolidated Statements of Earnings**	**3 months ended Sept. 30**		**9 months ended Sept. 30**	
		2011	2010	**2011**	2010
Interest rate contracts	Net interest expense	**8**	6	**8**	33
Long-term debt	Net interest expense	**(7)**	(6)	**(7)**	(33)
Net earnings impact		**1**	-	**1**	-

II. Non-Hedges

The Corporation enters into various derivative transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management

The Corporation enters into certain commodity transactions that are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are recognized in net earnings in the period the change occurs. The Corporation's outstanding energy trading derivative instruments that are not designated as hedging instruments were as follows:

(Thousands)	Sept. 30, 2011		Dec. 31, 2010		Jan. 1, 2010	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	52,587	40,030	26,553	24,924	14,107	14,844
Natural gas (GJ)	936,848	948,251	633,483	640,731	323,793	309,764
Transmission (MWh)	-	3,251	-	7,535	-	4,852
Oil (gallons)	-	2,772	-	5,040	-	-

b. Cross-Currency Interest Rate Swaps

Cross-currency interest rate swaps are periodically entered into in order to limit the Corporation's exposure to fluctuations in foreign exchange and interest rates. The liability resulting from an outstanding cross-currency interest rate swap is as follows:

As at	Sept. 30, 2011		Dec. 31, 2010			Jan. 1, 2010		
Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value liability	Maturity
-	-	-	-	-	-	AUD13	(2)	2010

c. Foreign Currency Contracts

The Corporation periodically enters into foreign exchange forwards to hedge future foreign denominated revenues and expenses for which hedge accounting is not pursued. These items are classified as held for trading, and changes in the fair values associated with these transactions are recognized in net earnings.

Outstanding notional amounts and fair values associated with these forward contracts are as follows:

As at	Sept. 30, 2011			Dec. 31, 2010			
Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
42	AUD41	(1)	2011	20	AUD20	1	2011
10	U.S.12	3	2011-2012	165	U.S.161	(4)	2011

As at	Jan. 1, 2010			
	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
	U.S.13	14	-	2010
	178	U.S.168	(1)	2010

d. Total Return Swaps

The Corporation also has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been chosen. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

e. Effect on the Condensed Consolidated Statements of Comprehensive Income

The Corporation utilizes a variety of derivatives in its trading activities, including certain commodity hedging activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported in earnings in the period the change occurs. For the three and nine months ended Sept. 30, 2011, the Corporation recognized a net unrealized gain of $61 million (Sept. 30, 2010 - loss of $4 million) and $81 million (Sept. 30, 2010 – loss of $4 million) respectively.

Foreign exchange derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss recorded in foreign exchange gain (loss) on the Condensed Consolidated Statements of Earnings. For the three months ended Sept. 30, 2011, a gain of $1 million (Sept. 30, 2010 - $5 million loss) was recognized and comprised of a net unrealized gain of $3 million (Sept. 30, 2010 - $1 million loss) and a net realized loss of $2 million (Sept. 30, 2010 - $4 million loss). For the nine months ended Sept. 30, 2011, a loss of $3 million (Sept. 30, 2010 - nil) was recognized and comprised of a net unrealized gain of $5 million (Sept. 30, 2010 - nil) and a net realized loss of $8 million (Sept. 30, 2010 - nil).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

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

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

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Trading segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information. In compliance with the Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board of Directors approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time.

VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2011 associated with the Corporation's proprietary energy trading activities was $6 million (Dec. 31, 2010 - $5 million, Jan. 1, 2010 - $3 million).

ii. Commodity Price Risk - Generation

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

TransAlta has entered into various financial contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta based on the average monthly Alberta Power Pool prices. While the contracts do not create any obligation for the physical delivery of electricity to other parties, the Corporation believes it has sufficient electrical generation available to satisfy these contracts and where able has designated these as cash flow hedges for accounting purposes.

As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through OCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Sept. 30, 2011 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $6 million (Dec. 31, 2010 - $52 million, Jan. 1, 2010 - $45 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment.

For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2011 associated with these transactions was $11 million (Dec. 31, 2010 - $6 million, Jan. 1, 2010 - nil).

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading and hedging interest rate derivatives outstanding as at the date of the Statement of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is a reasonable potential change in market interest rates over the next quarter.

	9 months ended Sept. 30			
	2011		2010	
	Net earnings increase(1)	**OCI loss(1)**	Net earnings increase(1)	OCI loss(1)
50 basis point change	**4**	**(11)**	5	-

(1) *This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.*

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, and the U.S. and Australian dollars, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI due to changes in foreign exchange rates associated with financial instruments outstanding as at the date of the Statement of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that a six cent (five cent – 2010) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

	9 months ended Sept. 30			
	2011		2010	
Currency	**Net earnings decrease[1]**	**OCI gain[1], [2]**	Net earnings decrease[1]	OCI gain[1], [2]
U.S.	**(3)**	**11**	-	-
AUD	**(1)**	**-**	(4)	8
EURO	**-**	**3**	(1)	-
Total	**(4)**	**14**	(5)	8

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments used as the hedging instruments in the net investment hedges have been excluded.

II. Credit Risk

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

At Sept. 30, 2011, TransAlta had two counterparties whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding. The Corporation has evaluated the risk of default related to these counterparties to be minimal.

The Corporation's maximum exposure to credit risk at Sept. 30, 2011, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Condensed Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables (Note 26) and including the fair value of open trading, net of any collateral held, at Sept. 30, 2011 was $42 million (Dec. 31, 2010 - $43 million, Jan. 1, 2010 - $63 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at Sept. 30, 2011:

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

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the period is presented below:

As at	Sept. 30, 2011	Dec. 31, 2010	Jan. 1, 2010
Allowance at beginning of period	**46**	49	57
Change in foreign exchange rates	**2**	(3)	(8)
Allowance at end of period	**48**	46	49

At Sept. 30, 2011, the Corporation did not have any significant past due trade receivables except as disclosed in Note 26.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong financial position and stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

TransAlta manages liquidity risk by monitoring liquidity on trading positions, preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital, reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Exposure Management Committee, senior management, and Board of Directors, and maintaining investment grade credit ratings.

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

	2011	2012	2013	2014	2015	2016 and thereafter	Total
Accounts payable and accrued liabilities	448	-	-	-	-	-	448
Collateral received	29	-	-	-	-	-	29
Debt(1)	2	320	630	209	1,374	1,718	4,253
Energy trading risk management (assets) liabilities(2)	(47)	(180)	(26)	(2)	11	33	(211)
Other risk management (assets) liabilities(2)	4	2	-	1	15	(2)	20
Interest on long-term debt	56	211	198	171	142	964	1,742
Dividends payable	66	-	-	-	-	-	66
Total	**558**	**353**	**802**	**379**	**1,542**	**2,713**	**6,347**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2015.
(2) Net risk management assets and liabilities.

C. Collateral

I. Financial Assets Provided as Collateral

At Sept. 30, 2011, the Corporation provided $36 million (Dec. 31, 2010 - $27 million, Jan. 1, 2010 - $27 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At Sept. 30, 2011, the Corporation received $29 million (Dec. 31, 2010 - $126 million, Jan. 1, 2010 - $86 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt to fall below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Sept. 30, 2011, the Corporation had posted collateral of $33 million (Dec. 31, 2010 - $17 million, Jan. 1, 2010 - $37 million) in the form of letters of credit, on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $49 million of collateral to its counterparties based upon the value of the derivatives at Sept. 30, 2011.

12. INVENTORY

Inventory held in the normal course of business which includes coal, emission credits, and natural gas is valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which also includes natural gas, is valued at fair value less costs to sell.

The classifications are as follows:

As at	**Sept. 30, 2011**	Dec. 31, 2010	Jan. 1, 2010
Coal	**92**	47	86
Natural gas	**6**	5	4
Purchased emission credits	**1**	1	-
Total	**99**	53	90

The change in inventory is outlined below:

Balance, Dec. 31, 2010	53
Net additions	46
Balance, Sept. 30, 2011	**99**
Balance, Jan. 1, 2010	90
Net consumed	(21)
Balance, Sept. 30, 2010	69

No inventory is pledged as security for liabilities.

For the three and nine months ended Sept. 30, 2011, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

13. LONG-TERM RECEIVABLE

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million.

14. PROPERTY, PLANT, AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant, and equipment is as follows:

	Land	Thermal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other	Total
Cost								
As at Dec. 31, 2010	71	4,601	1,793	2,427	920	982	246	11,040
Additions	-	(2)	1	-	-	302	17	318
Change in foreign exchange rates	-	44	-	-	2	1	-	47
Disposals	-	-	-	(1)	(2)	-	-	(3)
Retirement of assets	-	(28)	(3)	-	(1)	-	(5)	(37)
Asset impairment charges	-	-	-	(14)	-	-	-	(14)
Revisions to asset retirement costs	-	16	3	5	1	-	-	25
Transfers	2	965	8	73	15	(1,066)	7	4
As at Sept. 30, 2011	**73**	**5,596**	**1,802**	**2,490**	**935**	**219**	**265**	**11,380**
Accumulated depreciation								
As at Dec. 31, 2010	-	2,212	733	368	376	-	57	3,746
Change in foreign exchange rates	-	18	1	-	1	-	-	20
Depreciation	-	176	73	62	29	-	7	347
Disposals	-	-	-	(1)	(1)	-	-	(2)
Retirement of assets	-	(23)	(3)	-	-	-	-	(26)
Transfers	-	-	(1)	-	-	-	-	(1)
As at Sept. 30, 2011	**-**	**2,383**	**803**	**429**	**405**	**-**	**64**	**4,084**
Carrying amount								
As at Dec. 31, 2010	71	2,389	1,060	2,059	544	982	189	7,294
As at Sept. 30, 2011	**73**	**3,213**	**999**	**2,061**	**530**	**219**	**201**	**7,296**

During the three and nine months ended Sept. 30, 2011, the Corporation capitalized $8 million and $31 million, respectively, of interest to PP&E at a weighted average rate of 5.49 per cent and 5.34 per cent.

Asset Impairment Charges

During the third quarter of 2011, the Corporation recognized a pre-tax impairment charge of $5 million related to two assets within the renewables fleet, that were part of the acquisition of Canadian Hydro, in order to write the assets down to their estimated fair values. The impairment resulted from operational factors that impacted the expected useful lives of the assets. The impairment loss is included in the Generation segment.

During the second quarter of 2011, the Corporation completed an impairment assessment based on fair value estimates derived from the long range forecast and prices evidenced in the market place. As a result, the Corporation recorded a pre-tax impairment charge of $9 million on an asset within the renewables fleet that was part of the acquisition of Canadian Hydro, in order to write this asset down to its fair value. The impairment was included in the Generation segment.

During the second quarter of 2011, the Corporation wrote down certain capital spares to their estimated recoverable amount, resulting in a $4 million pre-tax increase in the depreciation expense of the Generation segment.

15. GOODWILL

Goodwill resulting from business combinations has been allocated to cash-generating units that are expected to benefit from the synergies of the acquisition, as follows:

As at	Sept. 30, 2011	Dec. 31, 2010	Jan. 1, 2010
Energy Trading	30	30	30
Renewables	417	417	417
Total goodwill	**447**	447	447

16. OTHER ASSETS

The components of other assets are as follows:

As at	Sept. 30, 2011	Dec. 31, 2010	Jan. 1, 2010
Deferred license fees	**23**	23	22
Project development costs	**31**	49	45
Deferred service costs	**18**	12	19
Keephills 3 transmission deposit	**8**	8	8
Other	**5**	10	9
Total other assets	**85**	102	103

17. DECOMMISSIONING AND OTHER PROVISIONS

The change in decommissioning and other provision balances is outlined below:

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2010	285	25	310
Liabilities incurred in period	19	54	73
Liabilities settled in period	(23)	(7)	(30)
Accretion of provisions	14	1	15
Transfer to liabilities held for sale	(1)	(1)	(2)
Revisions in estimated cash flows	(2)	3	1
Revisions in discount rates	11	-	11
Reversals	-	(1)	(1)
Change in foreign exchange rates	3	-	3
	306	74	380
Less: current portion	**(40)**	**(64)**	**(104)**
Balance, Sept. 30, 2011	**266**	**10**	**276**

	Decommissioning and restoration	Other	Total
Balance, Jan. 1, 2010	311	37	348
Liabilities incurred in period	2	3	5
Liabilities settled in period	(27)	(16)	(43)
Accretion of provisions	12	1	13
Revisions in estimated cash flows	(20)	1	(19)
Revisions in discount rates	33	-	33
Reversals	-	(5)	(5)
Change in foreign exchange rates	(2)	-	(2)
	309	21	330
Less: current portion	(39)	(7)	(46)
Balance, Sept. 30, 2010	270	14	284

18. LONG-TERM DEBT

The amounts outstanding are as follows:

As at	**Sept. 30, 2011**			Dec. 31, 2010			Jan. 1, 2010		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**1,010**	**1,010**	**2.2%**	645	645	1.4%	1,061	1,061	1.0%
Debentures	**831**	**851**	**6.6%**	1,058	1,076	6.7%	1,058	1,076	6.7%
Senior notes[3]	**2,004**	**1,964**	**6.0%**	1,931	1,902	6.0%	1,686	1,684	5.9%
Non-recourse	**376**	**383**	**5.9%**	374	383	5.9%	376	386	5.9%
Other	**45**	**45**	**6.6%**	52	52	6.7%	59	59	6.7%
	4,266	**4,253**		4,060	4,058		4,240	4,266	
Less: recourse current portion	**(318)**	**(318)**		(235)	(233)		(7)	(7)	
Less: non-recourse current portion	**(2)**	**(2)**		(2)	(2)		(2)	(2)	
Total long-term debt	**3,946**	**3,933**		3,823	3,823		4,231	4,257	

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

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

(3) U.S. face value at Sept. 30, 2011 - U.S.$1,900 million, Dec. 31, 2010 - U.S.$1,900 million, Jan. 1, 2010 - U.S.$1,600 million.

19. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

The components of deferred credits and other long-term liabilities are as follows:

As at	**Sept. 30, 2011**	Dec. 31, 2010	Jan. 1, 2010
Deferred coal revenues	**66**	61	51
Long-term power contracts	**27**	28	32
Present value of defined employee benefits obligation	**188**	161	138
Long-term incentive accruals	**16**	8	-
Other	**5**	11	15
Total deferred credits and other long-term liabilities	**302**	269	236

20. COMMON SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. At Sept. 30, 2011, the Corporation had 222.9 million common shares issued and outstanding. During the three months ended Sept. 30, 2011, 0.9 million (Sept. 30, 2010 - 0.7 million) common shares were issued for proceeds of $17 million (Sept. 30, 2010 - $15 million). During the nine months ended Sept. 30, 2011, 2.6 million (Sept. 30, 2010 – 1.1 million) common shares were issued for proceeds of $52 million (Sept. 30, 2010 - $19 million).

B. Stock Options

At Sept. 30, 2011, the Corporation had 1.8 million outstanding employee stock options (Dec. 31, 2010 - 2.2 million, Jan. 1, 2010 - 1.5 million). During the three months ended Sept. 30, 2011, and 2010 a nominal number of options expired, or were exercised or cancelled. During the nine months ended Sept. 30, 2011, 0.4 million options expired, or were exercised or cancelled (Sept. 30, 2010 – 0.1 million options expired, or were exercised or cancelled).

For the three and nine months ended Sept. 30, 2011, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was $1 million (Sept. 30, 2010 - $1 million), and $2 million (Sept. 30, 2010 - $2 million), respectively.

C. Dividend Reinvestment and Share Purchase ("DRASP") Plan

Under the terms of the DRASP plan, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. Under the terms of the DRASP plan, the Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time. During the three months ended Sept. 30, 2011, the Corporation issued 0.9 million (Sept. 30, 2010 - 0.7 million) common shares for $17 million (Sept. 30, 2010 - $15 million). For the nine months ended Sept. 30, 2011, the Corporation issued 2.5 million (Sept. 30, 2010 – 0.9 million) common shares for $51 million (Sept. 30, 2010 - $18 million).

D. Dividends

The following table summarizes the common share dividends declared in 2010 and 2011:

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Sept. 30, 2011	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Apr. 28, 2011	July 1, 2011	0.29	1	65	48	17
July 27, 2011	Oct. 1, 2011	0.29	65	65	-	-
Total		**0.58**	**66**	**130**		

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Jan. 29, 2010	April 1, 2010	0.29	-	63	60	3
April 1, 2010	July 1, 2010	0.29	-	64	49	15
July 22, 2010	Oct. 1, 2010	0.29	-	63	44	19
Oct. 28, 2010	Jan. 1, 2011	0.29	64	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	65	48	17
Total		1.45	129	319		

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

21. PREFERRED SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations. At Sept. 30, 2011, the Corporation had 12.0 million (Dec. 31, 2010 - 12.0 million, Jan. 1, 2010 - nil) preferred shares issued and outstanding.

B. Dividends

The following table summarizes the preferred share dividends declared in 2010 and 2011:

Date declared	**Payment date**	**Dividend per share ($)**	**Dividends payable as at Sept. 30, 2011**	**Total dividends**	**Dividends paid in cash**
Apr. 28, 2011	June 30, 2011	0.2875	**-**	3	3
July 27, 2011	Sept. 30, 2011	0.2875	**-**	4	4
Total		**0.5750**	**-**		

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends	Dividends paid in cash
Dec. 13, 2010	March 31, 2011	0.3497	1	4	4

22. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of, and changes in, AOCI are presented below:

Currency translation adjustment	
Balance, Dec. 31, 2010	**(27)**
Gains on translating net assets of foreign operations	**43**
Losses on financial instruments designated as hedges of foreign operations, net of tax[1]	**(42)**
Balance, Sept. 30, 2011	**(26)**
Cash flow hedges	
Balance, Dec. 31, 2010	**232**
Losses on derivatives designated as cash flow hedges, net of tax[2]	**(34)**
Reclassification of losses on derivatives designated as cash flow hedges to net earnings, net of tax[3]	**(203)**
Balance, Sept. 30, 2011	**(5)**
Employee benefits	
Balance, Dec. 31, 2010	**(20)**
Net actuarial losses on defined benefit plans, net of tax[4]	**(19)**
Balance, Sept. 30, 2011	**(39)**
Total AOCI	**(70)**

(1) Net of income tax recovery of 6 for the nine months ended Sept. 30, 2011.
(2) Net of income tax expense of 4 for the nine months ended Sept. 30, 2011.
(3) Net of income tax expense of 99 for the nine months ended Sept. 30, 2011.
(4) Net of income tax recovery of 7 for the nine months ended Sept. 30, 2011.

23. CAPITAL

TransAlta's capital is comprised of the following:

As at	**Sept. 30, 2011**	Dec. 31, 2010	Increase/ (decrease)
Current portion of long-term debt	**320**	237	83
Less: cash and cash equivalents	**(66)**	(35)	(31)
	254	202	52
Long-term debt	**3,946**	3,823	123
Equity			
Non-controlling interests	**380**	431	(51)
Preferred shares	**293**	293	-
Common shares	**2,256**	2,204	52
Contributed surplus	**8**	7	1
Retained earnings	**567**	431	136
AOCI	**(70)**	185	(255)
	7,380	7,374	6
Total capital	**7,634**	7,576	58

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2010.

TransAlta monitors key credit ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and seeks to manage the Corporation's capital in line with the following targets:

	Sept. 30, 2011	Dec. 31, 2010	Target
Cash flow to interest coverage (times)[1]	**4.6**	4.6	Minimum of 4
Cash flow to debt (%)[1]	**19.8**	19.6	Minimum of 20
Debt to invested capital (%)	**55.0**	53.1	Maximum of 60

(1) Last 12 months.

TransAlta routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and capital asset expenditure requirements.

TransAlta's formal dividend policy targets have remained unchanged from Dec. 31, 2010.

24. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. In terms of the Sundance Units 1 and 2 shut down and Sundance Unit 3 outage, while TransAlta believes the disputes will be resolved in the Corporation's favour, an unfavourble outcome could have a material impact on the Corporation's earnings and cash flow in an interim period but is unlikely to have a material impact on the total value of the Corporation's assets. For all other claims, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware, when taken as a whole, will have a material adverse effect on the Corporation.

25. COMMITMENTS

On March 28, 2011, TransAlta announced plans to build and operate the New Richmond 66 MW wind project in Quebec. New Richmond is contracted under a long-term 20-year electricity supply agreement with Hydro-Quebec Distribution. The capital cost of the project is estimated at approximately $205 million with commercial operations expected to commence during the fourth quarter of 2012.

26. PRIOR PERIOD REGULATORY DECISION

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$46 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator and the California Department of Water Resources during the 2000-2001 period. In addition, the California parties have sought additional refunds which to date have been rejected by FERC. TransAlta does not believe the California parties will be successful in obtaining additional refunds and is pursuing cost offsets to the refunds awarded by FERC. TransAlta established a U.S.$46 million provision to cover any potential refunds and continues to seek relief from this obligation. A final ruling is not expected in the near future.

27. GUARANTEES – LETTERS OF CREDIT

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Condensed Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Sept. 30, 2011 totalled $302 million (Dec. 31, 2010 - $297 million, Jan. 1, 2010 - $334 million) with no (Dec. 31, 2010 - nil, Jan. 1, 2010 - nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.0 billion (Dec. 31, 2010 - $2.0 billion, Jan. 1, 2010 - $2.1 billion) of committed credit facilities of which $0.7 billion (Dec. 31, 2010 - $1.1 billion, Jan. 1 2010 - $0.7 billion) is not drawn, and is available as of Sept. 30, 2011, subject to customary borrowing conditions.

In addition to the $0.7 billion available under the credit facilities, TransAlta also has $66 million of cash available.

28. SEGMENT DISCLOSURES

A. Each business segment assumes responsibility for its operating results.

3 months ended Sept. 30, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**584**	**45**	**-**	**629**
Fuel and purchased power *(Note 4)*	**258**	**-**	**-**	**258**
	326	**45**	**-**	**371**
Operations, maintenance and administration *(Note 4)*	**100**	**12**	**26**	**138**
Depreciation and amortization	**111**	**-**	**4**	**115**
Taxes, other than income taxes	**7**	**-**	**-**	**7**
Intersegment cost allocation (recovery)	**2**	**(2)**	**-**	**-**
	220	**10**	**30**	**260**
	106	**35**	**(30)**	**111**
Finance lease income *(Note 5)*	**2**	**-**	**-**	**2**
Equity income *(Note 6)*	**14**	**-**	**-**	**14**
Asset impairment charges *(Note 14)*	**(5)**	**-**	**-**	**(5)**
Other income				**1**
Foreign exchange gain *(Note 11)*				**1**
Net interest expense *(Notes 7 and 11)*				**(54)**
Earnings before income taxes				**70**

3 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Revenues	648	3	-	651
Fuel and purchased power *(Note 4)*	315	-	-	315
	333	3	-	336
Operations, maintenance and administration *(Note 4)*	102	4	13	119
Depreciation and amortization	120	-	5	125
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation (recovery)	1	(1)	-	-
	230	3	18	251
	103	-	(18)	85
Finance lease income *(Note 5)*	2	-	-	2
Equity income *(Note 6)*	11	-	-	11
Foreign exchange gain *(Note 11)*				1
Net interest expense *(Notes 7 and 11)*				(49)
Earnings before income taxes				50

9 months ended Sept. 30, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,865**	**97**	**-**	**1,962**
Fuel and purchased power *(Note 4)*	**655**	**-**	**-**	**655**
	1,210	**97**	**-**	**1,307**
Operations, maintenance and administration *(Note 4)*	**309**	**27**	**64**	**400**
Depreciation and amortization	**333**	**1**	**15**	**349**
Taxes, other than income taxes	**21**	**-**	**-**	**21**
Intersegment cost allocation (recovery)	**6**	**(6)**	**-**	**-**
	669	**22**	**79**	**770**
	541	**75**	**(79)**	**537**
Finance lease income *(Note 5)*	**6**	**-**	**-**	**6**
Equity income *(Note 6)*	**16**	**-**	**-**	**16**
Gain on sale of assets *(Note 3)*	**3**	**-**	**-**	**3**
Asset impairment charges *(Note 14)*	**(14)**	**-**	**-**	**(14)**
Other income				**2**
Net interest expense *(Notes 7 and 11)*				**(151)**
Earnings before income taxes				**399**

9 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Revenues	1,877	17	-	1,894
Fuel and purchased power *(Note 4)*	857	-	-	857
	1,020	17	-	1,037
Operations, maintenance and administration *(Note 4)*	317	13	51	381
Depreciation and amortization	332	1	14	347
Taxes, other than income taxes	21	-	-	21
Intersegment cost allocation (recovery)	4	(4)	-	-
	674	10	65	749
	346	7	(65)	288
Finance lease income *(Note 5)*	6	-	-	6
Equity income *(Note 6)*	8	-	-	8
Foreign exchange gain *(Note 11)*				4
Net interest expense *(Notes 7 and 11)*				(130)
Earnings before income taxes				176

For the three and nine months ended Sept. 30, 2011 and 2010, included above in Generation is $5 million (Sept. 30, 2010 - $4 million) and $17 million (Sept. 30, 2010 - $13 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects, respectively.

B. Selected Condensed Consolidated Statements of Financial Position Information

As at Sept. 30, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Goodwill *(Note 15)*	**417**	**30**	**-**	**447**
Total segment assets	**8,812**	**281**	**616**	**9,709**

As at Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Goodwill *(Note 15)*	417	30	-	447
Total segment assets	9,175	132	328	9,635

As at Jan. 1, 2010	Generation	Energy Trading	Corporate	Total
Goodwill *(Note 15)*	417	30	-	447
Total segment assets	8,862	148	443	9,453

C. Selected Condensed Consolidated Statements of Cash Flows Information

3 months ended Sept. 30, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment	**125**	**-**	**2**	**127**
Intangible assets	**1**	**-**	**4**	**5**

3 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	190	-	3	193
Intangible assets	1	(1)	7	7

9 months ended Sept. 30, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment	**314**	**-**	**4**	**318**
Intangible assets	**2**	**-**	**14**	**16**

9 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	605	-	10	615
Intangible assets	4	1	12	17

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

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

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2011	2010	**2011**	2010
Depreciation and amortization expense for reportable segments	**115**	125	**349**	347
Depreciation included in fuel, purchased power, and operating expenses *(Note 4)*	**10**	7	**29**	25
Gain on disposal of property, plant, and equipment	**1**	-	**5**	-
Depreciation and amortization expense per statements of cash flows	**126**	132	**383**	372

29. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2011	2010	**2011**	2010
Source (use):				
Accounts receivable	**(76)**	11	**(73)**	70
Prepaid expenses	**1**	(2)	**(6)**	(8)
Income taxes receivable	**(1)**	49	**17**	(10)
Inventory	**18**	28	**(40)**	19
Accounts payable and accrued liabilities	**95**	(31)	**(36)**	(95)
Decommissioning and other provisions	**10**	(4)	**28**	(21)
Income taxes payable	**6**	(2)	**2**	(5)
Change in non-cash operating working capital	**53**	49	**(108)**	(50)

30. EMPLOYEE FUTURE BENEFITS

The costs recognized during the period are presented below:

3 months ended Sept. 30, 2011	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	-	1	-	1
Interest cost	6	1	-	7
Expected return on plan assets	(6)	-	-	(6)
Past service costs	-	1	-	1
Defined benefit expense	-	3	-	3
Defined contribution expense	5	-	-	5
Net expense	**5**	**3**	**-**	**8**

3 months ended Sept. 30, 2010	Registered	Supplemental	Other	Total
Current service cost	1	-	-	1
Interest cost	5	2	1	8
Expected return on plan assets	(5)	-	-	(5)
Defined benefit expense	1	2	1	4
Defined contribution expense	4	-	-	4
Net expense	5	2	1	8

9 months ended Sept. 30, 2011	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	1	2	1	4
Interest cost	15	3	1	19
Expected return on plan assets	(16)	-	-	(16)
Past service costs	-	1	-	1
Defined benefit expense	-	6	2	8
Defined contribution expense	16	-	-	16
Net expense	**16**	**6**	**2**	**24**

9 months ended Sept. 30, 2010	Registered	Supplemental	Other	Total
Current service cost	2	1	1	4
Interest cost	15	3	2	20
Expected return on plan assets	(15)	-	-	(15)
Defined benefit expense	2	4	3	9
Defined contribution expense	15	-	-	15
Net expense	17	4	3	24

The amounts recognized through OCI during the period and balances of net actuarial gains (losses) are as follows:

	Registered	**Supplemental**	**Other**	**Total**
Balance, Dec. 31, 2010	(23)	(8)	3	(28)
Actuarial loss	(22)	(3)	(1)	(26)
Balance, Sept. 30, 2011	**(45)**	**(11)**	**2**	**(54)**

	Registered	Supplemental	Other	Total
Balance, Jan. 1, 2010	-	-	-	-
Actuarial loss	(34)	(7)	(3)	(44)
Balance, Sept. 30, 2010	(34)	(7)	(3)	(44)

31. SUBSIDIARIES AND JOINT VENTURES

Details of the Corporation's principal operating subsidiaries are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy trading
TransAlta Energy Marketing (U.S.) Inc.	U.S.	100	Energy trading
TransAlta Energy (Australia) Pty Ltd.	Australia	100	Generation and sale of electricity
Canadian Hydro Developers, Inc.	Canada	100	Generation and sale of electricity

Joint ventures at Sept. 30, 2011 included the following:

Jointly controlled assets	Ownership (per cent)	Description
Sheerness	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Canadian Utilities Limited
Fort Saskatchewan	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake	50	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power	50	Gas-fired plant in Australia operated by TransAlta
Genesee 3	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills 3	50	Coal-fired plant under construction in Alberta. The plant is being developed jointly with Capital Power Corporation and will be operated by TransAlta
Taylor Hydro	50	Hydro facility in Alberta operated by TransAlta
Soderglen	50	Wind generation facilities in Alberta operated by TransAlta
Pingston	50	Hydro facility in British Columbia operated by TransAlta
Project Pioneer	25	Carbon capture and storage facility operated by TransAlta

Jointly controlled entities	Ownership (per cent)	Description
CE Generation LLC	50	Geothermal and gas plants in the United States operated by CE Gen affiliates
Wailuku	50	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company

32. CENTRALIA COAL

On April 29, 2011, the Washington State Governor signed the TransAlta Energy Bill (the "Bill") into law. The Bill represents a collaborative agreement reached with the Governor's office, state legislators, and local environmental groups to establish a framework to transition from coal-fired energy produced at the Centralia Coal plant by 2025. The Memorandum of Agreement, which is part of the Bill, must be signed by the Governor no later than Jan. 1, 2012. We will continue to work with the State government and other impacted parties to successfully achieve and implement the transition plan.

The Bill, and associated Memorandum of Agreement, includes the following key elements:

- One unit will be shut down by the end of 2020 and the other by the end of 2025, at which time the site will be restored to an industrial land use standard;
- We will install Selective Non-Catalytic Reduction emission reduction technology before Jan. 1, 2013 and Washington State and the environmental community will advocate to the Environmental Protection Agency ("EPA") that we be exempt from installing more expensive Selective Catalytic Reduction ("SCR") technology. In the event the EPA imposes installation of SCRs at Centralia Coal, we are relieved of our obligations under the Bill;
- We will commit to fund $55 million over the life of the facility to support economic development, promoting energy efficiency and developing energy technologies related to the improvement of the environment;
- The Centralia coal plant is exempt from any Washington State imposed greenhouse gas ("GHG") regulations;
- We are no longer restricted to power contract terms of less than five years and Washington State Utilities that enter into contracts with Centralia Coal are permitted to earn a return on the contracts; and
- Washington State will provide expedited permitting for a replacement natural gas fired generation facility, which would also be exempt from Washington State GHG regulations.

SUPPLEMENTAL INFORMATION

		Sept. 30, 2011	Dec. 31, 2010
Closing market price (TSX) ($)		**22.81**	21.15
Price range for the last 12 months (TSX) ($)	High	**23.13**	23.98
	Low	**19.45**	19.61
Debt to invested capital including non recourse debt (%)		**55.0**	53.1
Debt to invested capital excluding non recourse debt (%)		**52.7**	50.7
Return on shareholders' equity (%)		**13.0**	9.6
Comparable return on shareholders' equity(1), (2) (%)		**10.2**	8.0
Return on capital employed(1) (%)		**9.5**	6.6
Comparable return on capital employed(1), (2) (%)		**8.0**	6.3
Cash dividends per share(1) ($)		**1.16**	1.16
Price/comparable earnings ratio(1) (times)		**17.8**	21.8
Earnings coverage(1) (times)		**3.0**	2.2
Dividend payout ratio based on net earnings(1) (%)		**72.3**	125.1
Dividend payout ratio based on comparable earnings(1), (2) (%)		**92.3**	149.8
Dividend payout ratio based on funds from operations(1), (2) (%)		**30.3**	39.6
Dividend yield(1) (%)		**5.1**	5.5
Cash flow to debt(1) (%)		**19.8**	19.6
Cash flow to interest coverage(1) (times)		**4.6**	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 MD&A.*

RATIO FORMULAS

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

Return on common shareholders' equity = net earnings attributable to common shareholders or earnings on a comparable basis / average equity applicable to common shareholders excluding Accumulated Other Comprehensive Income ("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.

Carbon Capture and Storage (CCS) - An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

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 shutdown of a generating unit due to an unanticipated breakdown.

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

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

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