MANAGEMENT'S DISCUSSION AND ANALYSIS

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

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2010 and 2009, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2009 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 28, 2010. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have two business segments: Generation and Energy Trading[(1)]. Our 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.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to self-sustaining foreign operations is reflected in the equity section of the Consolidated Balance Sheets.

(1) Our Energy Trading segment was referred to as "Commercial Operations and Development" in 2009.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Availability (%)	**91.0**	83.9	**88.1**	84.4
Production (GWh)	**12,742**	11,610	**35,857**	33,439
Revenue	**700**	666	**2,008**	2,007
Gross margin(1)	**380**	380	**1,137**	1,107
Operating income(1)	**98**	120	**287**	219
Net earnings	**38**	66	**156**	102
Net earnings per share, basic and diluted	**0.17**	0.34	**0.71**	0.52
Comparable earnings per share(1)	**0.17**	0.34	**0.57**	0.49
EBITDA(1)	**233**	241	**664**	595
Funds from operations(1)	**184**	178	**558**	463
Cash flow from operating activities	**230**	194	**502**	334
Cash flow from operating activities per share(1)	**1.05**	0.98	**2.28**	1.69
Free cash flow (deficiency)(1)	**107**	12	**74**	(196)
Cash dividends declared per share	**0.29**	0.29	**0.87**	0.87

	As at Sept. 30, 2010	As at Dec. 31, 2009
Total assets	**10,095**	9,775
Total long-term financial liabilities	**5,527**	5,537

AVAILABILITY & PRODUCTION

Availability for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant, lower planned outages at our Mississauga and Windsor facilities, and lower unplanned outages at Centralia Thermal.

Availability for the nine months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to lower planned outages at the Keephills plant, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal.

Production for the three months ended Sept. 30, 2010 increased 1,132 gigawatt hours (“GWh”) compared to the same period in 2009 primarily due to lower unplanned outages at Centralia Thermal, lower planned and unplanned outages at the Sundance plant, and higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro Developers, Inc. (“Canadian Hydro”), partially offset by the decommissioning of Wabamun.

Production for the nine months ended Sept. 30, 2010 increased 2,418 GWh compared to the same period in 2009 as a result of higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro, lower economic dispatching at Centralia Thermal, lower planned outages at the Keephills plant, lower planned and unplanned outages our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by the decommissioning of Wabamun, higher planned outages at Centralia Thermal, and the expiration of the long-term contract at Saranac.

(1) Gross margin, operating income, comparable earnings per share, earnings before interest, taxes, depreciation, and amortization (“EBITDA”), funds from operations, cash flow from operating activities per share, and free cash flow (deficiency) are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings and cash flow from operating activities.

NET EARNINGS

The primary factors contributing to the change in net earnings for the three and nine months ended Sept. 30, 2010 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net earnings, 2009	66	102
Increase in Generation gross margins	4	50
Decrease in Energy Trading gross margins	(4)	(20)
(Increase) decrease in OM&A costs	(5)	44
Increase in depreciation expense	(15)	(2)
Increase in net interest expense	(13)	(28)
(Increase) decrease in non-controlling interests	(5)	7
Decrease in income tax expense / increase in income tax recovery	12	15
Other	(2)	(12)
Net earnings, 2010	**38**	**156**

Generation gross margins for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 due to higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by the decommissioning of Wabamun, unfavourable pricing, and unfavourable foreign exchange rates.

For the nine months ended Sept. 30, 2010, Generation gross margins increased due to higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, lower planned outages at the Keephills plant, and lower planned and unplanned outages at our Sundance plant, partially offset by the expiration of the long-term contract at Saranac, unfavourable foreign exchange rates, the decommissioning of Wabamun, and unfavourable pricing.

Energy Trading gross margins for the three and nine months ended Sept. 30, 2010 decreased relative to the same period in 2009 primarily due to reduced margins from eastern regional spread strategies and narrowing geographical and inter-season spreads in the western region.

Operations, maintenance, and administration (“OM&A”) costs for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to the acquisition of Canadian Hydro, partially offset by targeted cost savings.

For the nine months ended Sept. 30, 2010, OM&A costs decreased due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by the acquisition of Canadian Hydro.

Depreciation expense for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to the acquisition of Canadian Hydro.

For the nine months ended Sept. 30, 2010, depreciation expense was comparable to the same period in 2009 as a result of an increased asset base primarily due to the acquisition of Canadian Hydro being offset by a change in the estimated useful lives of certain coal generating facilities and mining assets, a reduction in the estimate of the costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates.

Net interest expense for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to higher debt levels, partially offset by lower interest rates and higher capitalized interest.

For the nine months ended Sept. 30, 2010, net interest expense increased due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, favourable foreign exchange, higher capitalized interest, and lower interest rates.

Non-controlling interests increased for the three months ended Sept. 30, 2010 compared to the same period in 2009 due to higher earnings at TransAlta Cogeneration, L.P. (“TA Cogen”).

For the nine months ended Sept. 30, 2010, non-controlling interests decreased primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac, partially offset by higher earnings at TA Cogen.

Income tax expense decreased for the three months ended Sept. 30, 2010 compared to the same period in 2009 due to lower pre-tax earnings.

For the nine months ended Sept. 30, 2010, the income tax recovery increased due to the recovery related to the resolution of certain outstanding tax matters during the second quarter of 2010, partially offset by higher pre-tax earnings.

CASH FLOW

Cash flow from operating activities for the three months ended Sept. 30, 2010 increased $36 million compared to the same period in 2009 primarily due to favourable movements in working capital related to the timing of receiving certain tax related recoveries and favourable inventory movements.

For the nine months ended Sept. 30, 2010, cash flow from operating activities increased $168 million compared to the same period in 2009 as a result of higher cash earnings and favourable changes in working capital primarily due to favourable inventory movements and the timing of receiving certain tax related recoveries.

Free cash flow for the three and nine months ended Sept. 30, 2010 increased $95 million and $270 million, respectively, compared to the same period in 2009 due to higher cash earnings and lower sustaining capital expenditures.

SIGNIFICANT EVENTS

Three months ended Sept. 30, 2010

Sundance Unit 3 Uprate

On Sept. 13, 2010, we obtained approval from the Board of Directors for a 15 megawatt (“MW”) efficiency uprate at Unit 3 of our Sundance facility (“Unit 3”). The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Nine months ended Sept. 30, 2010

Resolution of Tax Matters

During the second quarter, we recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense also decreased by $14 million as a result of associated interest recoveries. $30 million of cash from the resolution of these tax matters was received during the third quarter and the balance is expected to be received before the end of the year.

Project Pioneer

On June 28, 2010, we announced that Enbridge Inc. will officially participate in the development of Project Pioneer, Canada's first fully-integrated carbon capture and storage ("CCS") project involving retro-fitting a coal-fired generation plant.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed chief financial officer, succeeding Brian Burden, who made a personal decision to retire from the Corporation. Mr. Burden assisted Mr. Gellner with the transition through Sept. 30, 2010.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 due to the mechanical failure of critical generator components. As a result, the expected capability levels for Unit 3 were reduced. Unit 3 returned to these reduced expected capability levels on June 23, 2010. The unit continues to operate at these reduced levels and no assurance can be given as to whether it will return to normal operating levels prior to the completion of major maintenance currently scheduled for the middle of 2012. As a result of the outage and subsequent derate, production has been reduced by 420 GWh for the nine months ended Sept. 30, 2010. Full year production is expected to decline by approximately 480 GWh.

In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed Force Majeure relief under the Power Purchase Arrangement ("PPA"). During the second quarter, we recorded an after-tax charge of $13 million, or 50 per cent of the penalties to June 30, 2010, representing the amount of penalties we are required to pay to the PPA Buyers pending a resolution of this matter. No additional penalties were incurred during the third quarter.

On Oct. 20, 2010, the Balancing Pool confirmed it agreed with our determination that the mechanical failure meets the requirements of a HILP event under the PPA. While this decision neither constitutes a determination of a Force Majeure event, nor provides a definitive resolution to the dispute, management believes this strengthens our position with regards to financial protection from the event.

Dividend Reinvestment and Share Purchase ("DRASP")

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 our 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. The Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

Centralia Thermal Memorandum of Understanding ("MOU")

On April 26, 2010, we announced that we signed an MOU with the State of Washington to enter discussions to develop an agreement to significantly reduce greenhouse gas ("GHG") emissions from the Centralia Thermal plant, and to provide replacement capacity by 2025. The MOU also recognizes the need to protect the value that Centralia Thermal brings to our shareholders. Details on the results of these discussions will be provided as they become available.

Decommissioning of Wabamun Plant

On March 31, 2010, we fully retired all units of the Wabamun plant as part of our previously-announced shut down. Over the next several years, we will complete the Wabamun plant remediation and reclamation work as approved by the Government of Alberta. Based on our review of our schedule and detailed costing of the decommissioning and reclamation activities, the asset retirement obligation associated with the Wabamun plant was reduced by $14 million during the first quarter, with the offset recorded as a recovery in depreciation.

Senior Notes Offering

On March 12, 2010, we completed our offering of U.S.$300 million senior notes maturing in 2040 and bearing an interest rate of 6.50 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

Summerview 2

On Feb. 23, 2010, our 66 MW Summerview 2 wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was $118 million.

Kent Hills Expansion

On Jan. 11, 2010, we announced that we had been awarded a 25-year contract to provide an additional 54 MW of wind power to New Brunswick Power Distribution and Customer Service Corporation. Under the agreement, we will expand our existing 96 MW Kent Hills wind facility to a total of 150 MW. The total capital cost of the project is estimated to be $100 million and is expected to begin commercial operations by the end of 2010. Natural Forces, who currently owns a 17 per cent interest in the existing Kent Hills wind facility, will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

Change in Economic Useful Life

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, our economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $7 million and $19 million for the three and nine months ended Sept. 30, 2010, respectively, compared to the same periods in 2009. The estimated annual pre-tax impact of this change is $29 million and will be reflected in depreciation expense and cost of goods sold.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

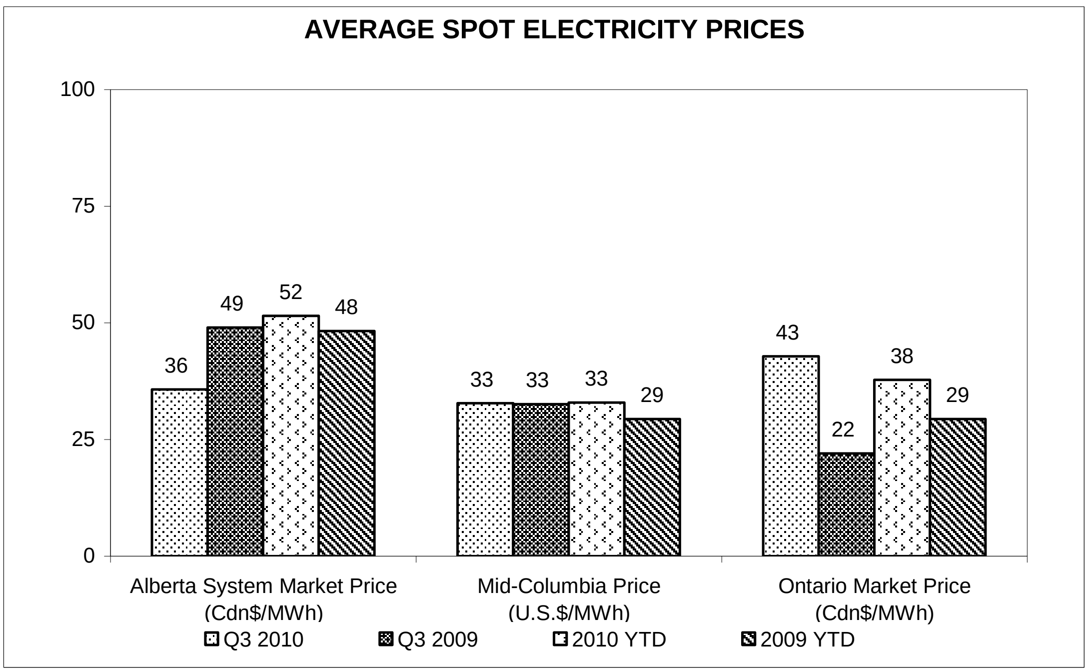
BUSINESS ENVIRONMENT

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 2009 Annual Report.

Electricity Prices

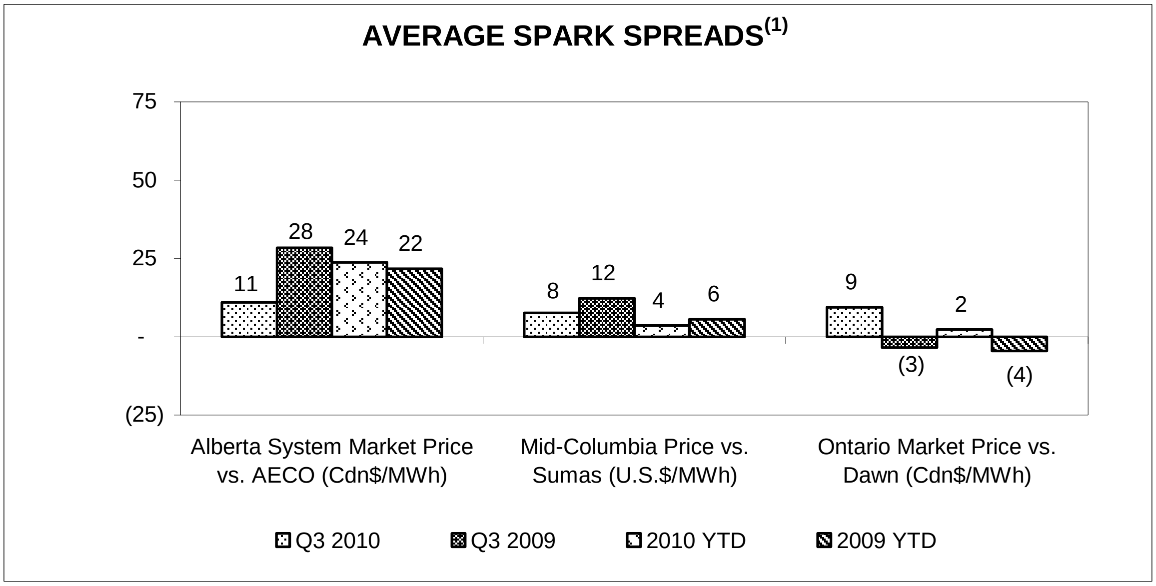
Please refer to the Business Environment section of the 2009 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the three and nine months ended Sept. 30, 2010 and 2009 in our three major markets are shown in the following graphs.



For the three months ended Sept. 30, 2010, average spot prices in Alberta decreased due to higher levels of supply as a result of higher unit availability. Prices increased in Alberta for the nine months ended Sept. 30, 2010 as a result of lower available supply in the first half of the year, partially offset by the higher availability during the third quarter. For the three and nine months ended Sept. 30, 2010, prices in the Pacific Northwest were comparable or increased slightly due to higher natural gas prices. Prices in Ontario were higher due to higher demand levels as a result of above-average weather temperatures.

During the third quarter of 2010, our consolidated power portfolio was 95 per cent contracted through the use of PPAs and other long-term contracts, which have historically provided stability to earnings. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2010 ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and from U.S.$50-$55 per MWh in the Pacific Northwest.



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

For the three months ended Sept. 30, 2010, average spark spreads decreased in Alberta due to lower power prices, while for the nine months ended Sept. 30, 2010 spark spreads increased due to higher power prices. For the three and nine months ended Sept. 30, 2010, spark spreads decreased in the Pacific Northwest due to gas prices increasing more than power prices. Ontario spark spreads were higher due to power prices increasing more than gas prices.

GENERATION: *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's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. During the first quarter of 2010, we began commercial operations at Summerview 2, a 66 MW expansion of our Summerview wind farm in southern Alberta. On March 31, 2010, we decommissioned our 279 MW Wabamun plant. At Sept. 30, 2010, Generation had 8,986 MW of gross generating capacity[(1)] in operation (8,562 MW net ownership interest) and 427 MW net under construction. 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 2009 Annual Report.*

The results of the Generation segment are as follows:

3 months ended Sept. 30	**2010** Total	**2010** Per installed MWh	2009 Total	2009 Per installed MWh
Revenues	**697**	**35.13**	659	35.59
Fuel and purchased power	**320**	**16.13**	286	15.45
Gross margin	**377**	**19.00**	373	20.14
Operations, maintenance, and administration	**131**	**6.60**	116	6.27
Depreciation and amortization	**121**	**6.10**	106	5.72
Taxes, other than income taxes	**7**	**0.35**	5	0.27
Intersegment cost allocation	**1**	**0.05**	8	0.43
Operating expenses	**260**	**13.10**	235	12.69
Operating income	**117**	**5.90**	138	7.45
Installed capacity (GWh)	**19,842**		18,516	
Production (GWh)	**12,742**		11,610	
Availability (%)	**91.0**		83.9	

9 months ended Sept. 30	**2010** Total	**2010** Per installed MWh	2009 Total	2009 Per installed MWh
Revenues	**1,991**	**33.47**	1,970	35.86
Fuel and purchased power	**871**	**14.64**	900	16.38
Gross margin	**1,120**	**18.83**	1,070	19.48
Operations, maintenance and administration	**419**	**7.04**	434	7.90
Depreciation and amortization	**333**	**5.60**	330	6.01
Taxes, other than income taxes	**21**	**0.35**	17	0.31
Intersegment cost allocation	**4**	**0.07**	24	0.44
Operating expenses	**777**	**13.06**	805	14.66
Operating income	**343**	**5.77**	265	4.82
Installed capacity (GWh)	**59,478**		54,938	
Production (GWh)	**35,857**		33,439	
Availability (%)	**88.1**		84.4	

(1) We measure capacity as net maximum capacity (see glossary for definition of this and other key items) which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.

Production and Gross Margins

Generation's production volumes, fuel and purchased power costs, and gross margins based on geographical regions are presented below.

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	902	1,240	52	14	38	41.94	11.29	30.65
Renewables	627	2,751	22	3	19	8.00	1.09	6.91
Total Western Canada	**7,712**	**11,735**	**283**	**108**	**175**	**24.12**	**9.21**	**14.91**
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	17.90
Total Eastern Canada	**1,382**	**2,996**	**135**	**65**	**70**	**45.06**	**21.70**	**23.36**
Coal	2,626	3,038	197	127	70	64.85	41.80	23.05
Gas	678	1,698	42	19	23	24.73	11.19	13.54
Renewables	344	375	40	1	39	106.67	2.67	104.00
Total International	**3,648**	**5,111**	**279**	**147**	**132**	**54.59**	**28.76**	**25.83**
	12,742	**19,842**	**697**	**320**	**377**	**35.13**	**16.13**	**19.00**

3 months ended Sept. 30, 2009	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	6,002	8,249	223	89	134	27.03	10.79	16.24
Gas	943	1,186	48	16	32	40.47	13.49	26.98
Renewables	366	2,103	24	1	23	11.41	0.48	10.93
Total Western Canada	7,311	11,538	295	106	189	25.57	9.19	16.38
Gas	782	1,656	80	44	36	48.31	26.57	21.74
Renewables	36	212	3	-	3	14.15	-	14.15
Total Eastern Canada	818	1,868	83	44	39	44.43	23.55	20.88
Coal	2,250	3,038	192	114	78	63.20	37.52	25.68
Gas	868	1,698	50	21	29	29.45	12.37	17.08
Renewables	363	374	39	1	38	104.28	2.67	101.61
Total International	3,481	5,110	281	136	145	54.99	26.61	28.38
	11,610	18,516	659	286	373	35.59	15.45	20.14

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	238	354	25.10	10.09	15.01
Gas	2,963	3,626	169	57	112	46.61	15.72	30.89
Renewables	1,801	8,216	97	7	90	11.81	0.85	10.96
Total Western Canada	**23,371**	**35,423**	**858**	**302**	**556**	**24.22**	**8.52**	**15.70**
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	9,015	525	334	191	58.24	37.05	21.19
Gas	1,613	5,038	107	43	64	21.24	8.54	12.70
Renewables	946	1,112	91	4	87	81.83	3.60	78.23
Total International	**8,710**	**15,165**	**723**	**381**	**342**	**47.68**	**25.13**	**22.55**
	35,857	**59,478**	**1,991**	**871**	**1,120**	**33.47**	**14.64**	**18.83**

9 months ended Sept. 30, 2009	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	17,946	24,473	597	253	344	24.39	10.34	14.05
Gas	2,983	3,517	161	58	103	45.78	16.49	29.29
Renewables	1,298	6,240	83	5	78	13.30	0.80	12.50
Total Western Canada	22,227	34,230	841	316	525	24.57	9.23	15.34
Gas	2,551	4,914	282	171	111	57.39	34.80	22.59
Renewables	150	629	12	-	12	19.08	-	19.08
Total Eastern Canada	2,701	5,543	294	171	123	53.04	30.85	22.19
Coal	5,278	9,015	550	335	215	61.01	37.16	23.85
Gas	2,218	5,038	179	66	113	35.53	13.10	22.43
Renewables	1,015	1,112	106	12	94	95.32	10.79	84.53
Total International	8,511	15,165	835	413	422	55.06	27.23	27.83
	33,439	54,938	1,970	900	1,070	35.86	16.38	19.48

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 2009 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, 2010 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2009	7,311	22,227
Lower planned outages at Keephills	-	865
Higher merchant volumes due to Sundance 5 uprate	117	347
Higher wind volumes primarily due to the acquisition of Canadian Hydro	124	300
Lower planned outages at Sundance	209	270
Lower unplanned outages at Sundance	317	235
Higher hydro volumes primarily due to the acquisition of Canadian Hydro	137	202
Higher PPA customer demand	104	53
Decommissioning of Wabamun	(516)	(973)
Lower production at natural gas-fired facilities	(71)	(115)
Lower (higher) unplanned outages at Sheerness	9	(60)
Other	(29)	20
Production, 2010	**7,712**	**23,371**

The primary factors contributing to the change in gross margin for the three and nine months ended Sept. 30, 2010 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2009	189	525
Lower planned outages at Keephills	-	36
Lower planned outages at Sundance	7	17
Higher wind volumes primarily due to the acquisition of Canadian Hydro	3	14
Higher hydro volumes primarily due to the acquisition of Canadian Hydro	7	13
Higher merchant volumes due to Sundance 5 uprate	4	11
Lower unplanned outages at Sundance	9	8
Unfavourable pricing	(23)	(40)
Decommissioning of Wabamun	(20)	(26)
Higher unplanned outages at Sheerness	-	(5)
Other	(1)	3
Gross margin, 2010	**175**	**556**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2009 Annual Report for further details on our Eastern operations.

Production for the three and nine months ended Sept. 30, 2010 increased 564 GWh and 1,075 GWh, respectively, primarily due to higher wind volumes as a result of the acquisition of Canadian Hydro and market conditions at Sarnia.

For the three months ended Sept. 30, 2010, gross margin increased $31 million due to higher wind volumes as a result of the acquisition of Canadian Hydro.

Gross margin increased $99 million for the nine months ended Sept. 30, 2010 due to higher wind volumes as a result of the acquisition of Canadian Hydro and the new agreement with the Ontario Power Authority at our Sarnia regional cogeneration power plant that came into effect in the third quarter of 2009.

International

Our International assets consist of coal, natural gas, hydro, and geothermal facilities in various locations in the United States, and natural gas assets in Australia. Refer to the Discussion of Segmented Results section of our 2009 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, 2010 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2009	3,481	8,511
Economic dispatching at Centralia Thermal	(108)	870
Lower unplanned outages at Centralia Thermal	592	414
Higher planned outages at Centralia Thermal	(107)	(410)
Expiration of long-term contract at Saranac	-	(357)
Lower production at natural gas-fired facilities	(200)	(211)
Lower production at geothermal facilities	-	(93)
Other	(10)	(14)
Production, 2010	**3,648**	**8,710**

The primary factors contributing to the change in gross margin for the three and nine months ended Sept. 30, 2010 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2009	145	422
Expiration of long-term contract at Saranac	-	(42)
Unfavourable foreign exchange	(6)	(35)
Lower production at natural gas-fired facilities	(6)	(6)
Mark-to-market movements	(2)	(5)
Economic dispatching at Centralia Thermal	-	(5)
Higher coal costs	(2)	(2)
Favourable pricing	1	17
Lower outages at Centralia Thermal	8	5
Other	(6)	(7)
Gross margin, 2010	**132**	**342**

The long-term contract between our Saranac facility and New York State Electric and Gas expired in June 2009. The facility now operates under a combined capacity and merchant dispatch contract, resulting in a corresponding $13 million decrease in depreciation expense for the nine months ended Sept. 30, 2010. Further, as a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. The net pre-tax earnings impact of the expiration of this contract is a decrease of approximately $10 million for the nine months ended Sept. 30, 2010.

Operations, Maintenance and Administration Expense

OM&A costs for the three months ended Sept. 30, 2010 increased compared to the same period in 2009 primarily due to the acquisition of Canadian Hydro and costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010, partially offset by targeted cost savings.

For the nine months ended Sept. 30, 2010, OM&A costs decreased due to lower planned outages, favourable foreign exchange rates, and targeted cost savings partially offset by the acquisition of Canadian Hydro and costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010.

Depreciation Expense

The primary factors contributing to the change in depreciation expense for the three and nine months ended Sept. 30, 2010 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Depreciation and amortization expense, 2009	106	330
Increased asset base primarily due to the acquisition of Canadian Hydro	16	52
Asset retirements	7	7
Change in useful lives	(7)	(19)
Reduction in decommissioning costs at Wabamun	-	(14)
Expiration of long-term contract at Saranac	-	(13)
Favourable foreign exchange	(2)	(12)
Other	1	2
Depreciation and amortization expense, 2010	**121**	**333**

ENERGY TRADING: *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving a positive gross margin while remaining within Value at Risk ("VaR") limits is a key measure of Energy Trading's activities.*

Energy Trading is responsible for the execution management of certain commercial activities for our current generating assets. Energy Trading also manages available merchant 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, coal, and transmission capacity. 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 2009 Annual Report.

The results of the Energy Trading segment are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Gross margin	**3**	7	**17**	37
Operations, maintenance, and administration	**4**	9	**12**	25
Depreciation and amortization	**-**	1	**1**	2
Intersegment cost recovery	**(1)**	(8)	**(4)**	(24)
Operating expenses	**3**	2	**9**	3
Operating income	**-**	5	**8**	34

For the three and nine months ended Sept. 30, 2010, gross margin decreased relative to the same periods in 2009 primarily due to reduced margins from eastern regional spread strategies and narrowing geographical and inter-season spreads in the western region.

For the three and nine months ended Sept. 30, 2010, OM&A costs and the intersegment fee decreased relative to the same periods in 2009 as a result of support costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Interest on debt	**63**	46	**181**	132
Interest income from resolution of certain outstanding tax matters	**-**	-	**(14)**	-
Capitalized interest	**(13)**	(10)	**(35)**	(27)
Interest income	**(1)**	(3)	**(2)**	(6)
Other	**-**	3	**-**	3
Net interest expense	**49**	36	**130**	102

The change in net interest expense for the three and nine months ended Sept. 30, 2010, compared to the same periods in 2009 is shown below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net interest expense, 2009	36	102
Higher debt levels	20	65
Interest income from resolution of certain outstanding tax matters	-	(14)
Favourable foreign exchange	(2)	(10)
Higher capitalized interest	(3)	(8)
Lower interest rates	(4)	(9)
Lower interest income	2	4
Net interest expense, 2010	**49**	**130**

OTHER INCOME

During the first quarter of 2009, we settled an outstanding commercial issue that was related to our previously held Mexican equity investment and recorded as a pre-tax gain of $7 million. During the second quarter of 2009, we recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm.

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three months ended Sept. 30, 2010 increased $5 million compared to the same period in 2009 due to higher earnings at TA Cogen.

For the nine months ended Sept. 30, 2010, earnings attributable to non-controlling interests decreased $7 million due to lower earnings at CE Generation, LLC resulting from the expiration of the long-term contract at Saranac, partially offset by higher earnings at TA Cogen.

INCOME TAXES

A reconciliation of income taxes and effective tax rates on comparable income before income taxes is presented below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Earnings before income taxes	**42**	82	**141**	102
Settlement of commercial issue	**-**	-	**-**	(7)
Change in life of Centralia parts	**-**	-	**-**	2
Comparable earnings[1] before income taxes	**42**	82	**141**	97
Income tax expense (recovery)	**4**	16	**(15)**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**30**	-
Income tax expense on settlement of commercial issue	**-**	-	**-**	(1)
Income tax recovery on change in life of Centralia parts	**-**	-	**-**	1
Income tax expense excluding non-comparable items	**4**	16	**15**	-
Effective tax rate on earnings before income taxes (%)	**10**	20	**(11)**	-
Effective tax rate on comparable earnings before income taxes (%)	**10**	20	**11**	-

The income tax expense excluding non-comparable items decreased for the three months ended Sept. 30, 2010 compared to the same period in 2009 due to lower pre-tax earnings. For the nine months ended Sept. 30, 2010, the income tax expense excluding non-comparable items increased due to higher pre-tax earnings.

The effective tax rate decreased for the three months ended Sept. 30, 2010 and increased for the nine months ended Sept. 30, 2010 compared to the same periods in 2009 primarily due to certain deductions that do not fluctuate with earnings and a change in the mix of jurisdictions where pre-tax income is earned.

(1) Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of this item, as well as a reconciliation to net earnings.

FINANCIAL POSITION

The following chart highlights significant changes in the Consolidated Balance Sheets from Dec. 31, 2009 to Sept. 30, 2010:

	Increase/ (Decrease)	Primary factors explaining change
Accounts receivable	(60)	Timing of customer receipts
Income taxes receivable	14	Expected receivable related to the resolution of certain outstanding tax matters
Inventory	(21)	Higher production at coal facilities
Long-term receivables	(49)	Partial payment received with remainder reclassified to current taxes receivable
Risk management assets (current and long-term)	256	Price movements
Property, plant, and equipment, net	211	Capital additions, partially offset by depreciation expense
Intangible assets	(22)	Amortization expense
Other assets	10	Increase in defined benefit pension asset and new growth and productivity initiatives
Accounts payable and accrued liabilities	(115)	Timing of payments, combined with lower operational expenditures
Collateral received	83	Collateral collected from counterparties as a result of a change in forward prices
Long-term debt (including current portion)	242	Issuance of U.S.$300 senior notes, partially offset by repayments of other long-term debt
Risk management liabilities (current and long-term)	(12)	Price movements
Asset retirement obligation (including current portion)	(33)	Revised cost estimate of the decommissioning of our Wabamun plant and foreign exchange
Deferred credits and other long-term liabilities	17	Timing of deferred revenues and accrued benefits
Net future income tax liabilities (including current portions)	70	Tax effect on the increase in net risk management assets
Non-controlling interests	(39)	Distributions in excess of earnings attributable to non-controlling interests and hedging activity
Shareholders' equity	143	Net earnings, and movements in AOCI, partially offset by dividends declared

FINANCIAL INSTRUMENTS

Refer to *Note 7* of the notes to the consolidated financial statements within our 2009 Annual Report and *Note 6* of the interim consolidated financial statements as at and for the three and nine months ended Sept. 30, 2010 for details on Financial Instruments. Refer to the Risk Management section of our 2009 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, 2009.

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under Canadian GAAP 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 the acquisition of 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, 2010, Level III financial instruments had a net liability carrying value of $10 million (Dec. 31, 2009 – $26 million).

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2010 compared to the three and nine months ended Sept. 30, 2009:

3 months ended Sept. 30	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**43**	54	
Provided by (used in):			
Operating activities	**230**	194	Favourable changes in working capital of $30 million related to the timing of receiving certain tax related recoveries and favourable inventory movements.
Investing activities	**(126)**	(270)	Decrease in capital spending of $85 million and an increase in collateral received from counterparties of $75 million.
Financing activities	**(72)**	110	Lower borrowings primarily as a result of lower capital spending, increased collateral receipts and favourable movements in working capital.
Translation of foreign currency cash	**5**	(2)	
Cash and cash equivalents, end of period	**80**	86	

9 months ended Sept. 30	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**82**	50	
Provided by (used in):			
Operating activities	**502**	334	Higher cash earnings of $95 million and favourable changes in working capital of $73 million, due to favourable movements in inventory and the timing of receiving certain tax related recoveries.
Investing activities	**(523)**	(562)	Decrease in capital spending of $88 million, partially offset by a decrease in the amount of collateral received from counterparties of $19 million.
Financing activities	**17**	266	Lower borrowings as a result of higher cash flow from operating activities and lower capital spending.
Translation of foreign currency cash	**2**	(2)	
Cash and cash equivalents, end of period	**80**	86	

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 a 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 partners, and interest and principal repayments on debt securities.

Debt

Recourse and non-recourse debt totalled $4.7 billion at Sept. 30, 2010 compared to $4.4 billion at Dec. 31, 2009. Total debt increased from Dec. 31, 2009 primarily due to growth capital expenditures.

Credit Facilities

At Sept. 30, 2010, we have a total of $2.1 billion (Dec. 31, 2009 – $2.1 billion) of committed credit facilities of which $0.8 billion (Dec. 31, 2009 – $0.7 billion) is not drawn and is available, subject to customary borrowing conditions. At Sept. 30, 2010, the $1.3 billion (Dec. 31, 2009 – $1.4 billion) of credit utilized under these facilities is comprised of actual drawings of $1.0 billion (Dec. 31, 2009 – $1.1 billion) and letters of credit of $0.3 billion (Dec. 31, 2009 – $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2012, with the remainder comprised of bilateral credit facilities which mature between the fourth quarter of 2011 and 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.8 billion available under the credit facilities, we also have $80 million of cash.

Share Capital

On Oct. 28, 2010, we had 220.3 million common shares outstanding.

At Sept. 30, 2010, we had 219.5 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended Sept. 30, 2010, 0.7 million (Sept. 30, 2009 – 0.1 million) common shares were issued for $15 million under the terms of the DRASP plan (Sept. 30, 2009 – nil). During the nine months ended Sept. 30, 2010, 1.1 million (Sept. 30, 2009 – 0.3 million) common shares were issued for $19 million (Sept. 30, 2009 – nil), of which $18 million was issued under the terms of the DRASP plan.

During the nine months ended Sept. 30, 2010 and 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid program prior to its expiry on May 6, 2010.

We employ a variety of stock-based compensation to align employee and corporate objectives. At Sept. 30, 2010, we had 2.3 million outstanding employee stock options (Dec. 31, 2009 – 1.5 million), reflecting 0.9 million stock options granted on Feb. 1, 2010, at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2011, and expire after 10 years. During the three months ended Sept. 30, 2010, a nominal number of options expired, or were exercised or cancelled (Sept. 30, 2009 – nil). During the nine months ended Sept. 30, 2010, 0.1 million options expired, or were exercised or cancelled (Sept. 30, 2009 – 0.1 million expired, 0.1 million 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, 2010, we provided letters of credit totalling $332 million (Dec. 31, 2009 – $334 million) and cash collateral of $32 million (Dec. 31, 2009 – $27 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Balance Sheets under "Risk Management Liabilities" and "Asset Retirement Obligation."

CLIMATE CHANGE AND THE ENVIRONMENT

Canada

Following the federal government's announcement on June 23, 2010 for plans to regulate GHG emissions from the coal-fired power sector, we have been in discussions with both the Governments of Canada and Alberta about the design of the proposed regulation. The proposal, if passed into law, would become effective in 2015 and require existing coal-fired plants to meet a natural gas emissions performance standard by their 45th year of operation, or the end of their PPA term, whichever is later. If the coal-fired plants do not meet the required performance standard by that time, they would be required to cease operations. Until then, the plants would not be subject to any federal GHG compliance costs.

While the above development would provide regulatory clarity for future capital decision-making, there are some issues that will have to be resolved, including how transition costs are recovered by generators, the impacts on Alberta PPAs, standards for emission requirements for natural gas-fired facilities, and how CCS will continue to be supported. The effect of this proposal on the Alberta deregulated market and PPA structure must also be considered. The federal government has announced its intention to put forward the first draft of the regulation in early 2011.

In Ontario, the provincial government continues to develop its plans for a GHG regulatory framework consistent with the Western Climate Initiative model, which uses a cap and trade design as the regulatory vehicle. Details of the Government of Ontario's proposed design have not yet been released.

Mercury capture technology is in the final installation stages at our Alberta coal-fired plants, and will be operational before the end of 2010 to be compliant with the Alberta regulation to begin removing 70 per cent of mercury emissions by Jan. 1, 2011.

United States

In the U.S., the future direction on climate change has not been resolved. Legislative proposals in the Senate continue to be discussed but none have been adopted. We do not expect any further significant developments until after the U.S. mid-term elections, and not likely before 2011. Meanwhile, the U.S. Environmental Protection Agency ("EPA") continues with plans to regulate GHG emissions from power plants and other industries beginning in January 2011. After that point, new or modified plants would be required to employ best available technology to reduce their GHG emissions. The definition of best available technology has not yet been determined. This EPA initiative is expected to face legal challenges as well as some opposition from Congress.

Canada continues to state that it will follow the U.S. lead and timing on all sectors except for the coal-fired power sector.

In Washington, we have been working with the State government to develop a plan to reduce GHG emissions from our Centralia plant, consistent with the Governor's Executive Order to reduce emissions by approximately 50 per cent of current levels by 2025. Discussions with the State and other stakeholders are ongoing.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form, many of our activities and properties are subject to environmental requirements, as well as changes in or liabilities under these requirements, which may have a materially adverse affect upon our consolidated financial results.

2010 OUTLOOK

In 2010, we anticipate double digit growth in comparable earnings per share based upon the significant factors that are discussed below.

Business Environment

Power Prices

For the remainder of 2010, power prices are expected to be at or lower than 2009 levels due to low natural gas prices. In Alberta, the longer-term fundamentals of the market remain strong and increased production at the oil sands is expected to drive load growth, keeping Alberta prices near the same levels as seen in the fourth quarter of 2009. In the Pacific Northwest, natural gas prices and the economy will be the main drivers behind power prices. Both of these fundamental drivers remain weak and are likely to result in lower power prices compared to 2009. Natural gas prices are expected to remain low through 2011 and 2012.

Environmental Legislation

With the Government of Canada's announcement on plans for regulating GHG emissions from the coal-fired power sector on June 23, 2010, there may be some regulatory clarity for our coal-fired facilities in the future. The finalization of GHG emission regulations for the coal-fired power sector is expected in 2011, for implementation in 2015. For other Canadian industrial sectors, the federal government has expressed its intention to coordinate the timing and structure of its GHG regulatory framework with the U.S. In the U.S. it is not clear if climate change legislation will prevail or if regulation will instead 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.

Economic Environment

While we expect our results from operations in 2010 to be impacted by the current economic environment, we expect that this impact will be somewhat mitigated by the contracted production and prices through our Alberta PPAs and other long-term contracts.

We continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase for the remainder of 2010 due to the commissioning of Kent Hills 2 and Ardenville. Overall production for 2010 is expected to increase due to lower planned and unplanned outages across the fleet and the acquisition of Canadian Hydro, partially offset by the decommissioning of Wabamun. Availability for 2010 is expected to increase due to lower planned and unplanned outages across the fleet, with the overall fleet availability for 2010 expected to be between approximately 89 to 90 per cent.

Commodity Hedging

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis we target being up to 90 per cent contracted for the upcoming year, stepping down to 70 per cent in the fourth year. As at the end of the third quarter, approximately 94 per cent of our 2010 capacity was contracted. The average price of our short-term physical and financial contracts in 2010 ranges from $60-$65 per MWh in Alberta, and from U.S.$50-$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 2010, on a standard cost basis, are expected to increase five to 10 per cent compared to the prior year as a result of increased depreciation due to mine capital investment and higher diesel costs.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2010 is expected to be consistent with 2009.

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 per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs for 2010 are expected to be lower than 2009 as costs related to Canadian Hydro are expected to be more than offset by lower planned maintenance, operational synergies, and productivity measures. OM&A costs per installed MWh for 2010 are expected to decrease primarily as a result of lower planned maintenance and an increase in installed capacity due to the acquisition of Canadian Hydro.

Energy Trading

Earnings from our Energy Trading segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to enhance earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading to contribute between $30 million and $50 million in gross margin. The annual objective for Energy Trading gross margin contribution has decreased 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. dollar by offsetting foreign denominated assets with foreign denominated liabilities and 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 2010 is expected to be higher than 2009 mainly due to higher debt balances. 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. To mitigate this risk and to provide for sufficient liquidity to meet our requirements, we maintain $2.1 billion of committed credit facilities and continually monitor our exposures and obligations.

Accounting Estimates

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of our 2009 Annual MD&A, are based on the current economic environment and outlook. While we currently do not anticipate significant changes to these estimates, 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. The unrealized gains or losses related to our risk management assets and liabilities are not expected to impact our future cash flows as they are generally settled at the contracted prices.

Income Taxes

The effective tax rate for 2010, excluding recoveries related to the resolution of certain outstanding tax matters, is expected to be approximately 17 to 22 per cent.

Capital Expenditures

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

Growth Capital Expenditures

We have seven significant growth capital projects that are currently in progress with targeted completion dates between Q4 2010 and Q4 2012. A summary of each of these projects and the project we completed in 2010 is outlined below:

	Total Project		2010		Target	
Project	**Estimated spend**	**Incurred to date(1)**	**Estimated spend**	**Incurred to date(1)**	**completion date**	**Details**
Keephills 3	988	885	225 - 245	178	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Summerview 2	118	117	10 - 15	11	Commercial operations began Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	4	0 - 5	3	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	3	5 - 10	2	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	118	105 - 115	91	Q4 2010	A 69 MW wind farm in southern Alberta
Bone Creek	48	41	50 - 55	37	Q1 2011	An 18 MW hydro facility in British Columbia
Kent Hills 2	100	78	80 - 85	60	Q4 2010	A 54 MW expansion of our wind farm in New Brunswick
Sundance Unit 3 uprate	27	1	0 - 5	1	Q4 2012	A 15 MW efficiency uprate at our Sundance facility
Total growth	**1,484**	**1,247**	**475 - 535**	**383**		

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

The total project spend and 2010 estimated spend for Summerview 2 has decreased compared to prior estimates to reflect cost savings associated with the early delivery of wind turbines.

(1) Represents amounts incurred as of Sept. 30, 2010, including the impact of project hedges.

The 2010 estimated spend for Ardenville has increased and the target completion date has been revised to reflect accelerated construction during the third and fourth quarters of this year. The 2010 estimated spend for Bone Creek has increased compared to prior period estimates primarily due to a change in the timing of project spend and associated recoveries. The total project spend in each case remains unchanged.

Sustaining Capital Expenditures

For 2010, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Incurred to date(1)
Routine capital	Expenditures to maintain our existing generating capacity	120 - 140	90
Productivity capital	Projects to improve power production efficiency	10 - 15	7
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	20 - 25	6
Planned maintenance	Regularly scheduled major maintenance	125 - 140	99
Total sustaining expenditures		**275 - 320**	202

Details of the 2010 planned maintenance program are outlined as follows:

	Coal	Gas	Renewables	Expected cost	Incurred to date(1)
Capitalized	70 - 75	30 - 35	25 - 30	**125 - 140**	99
Expensed	65 - 70	0 - 5	-	**65 - 75**	61
	135 - 145	30 - 40	25 - 30	**190 - 215**	160

	Coal	Gas	Renewables	Total	Incurred to date (1)
GWh lost	2,465 - 2,475	160 - 170	-	**2,625 - 2,645**	2,467

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing bank 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.

(1) Represents amounts incurred as of Sept. 30, 2010.

RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Sept. 30, 2010, TAGP had received $59 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TA Cogen, which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. The notional gas volume in the swap transaction is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS") Convergence

On May 8, 2009, the Accounting Standards Board re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. Our project to convert to IFRS consists of the following phases:

Phase	Description	Status
Diagnostic	In-depth identification and analysis of differences between Canadian GAAP and IFRS	Complete
Design and planning	Cross-functional, issue-specific teams analyze the key areas of convergence, and along with Information Technology and Internal Control resources, determine process, system, and financial reporting controls changes required for the conversion to IFRS	Complete
Solution development	Plans to address identified conversion issues are developed and tested in a controlled environment. Staff training programs and internal communication plans are implemented to communicate process changes as a result of the conversion to IFRS	Nearing completion
Implementation	Processes required for dual reporting in 2010 and full convergence in 2011 are implemented in a live environment with change management in place for a successful transition to steady state	In progress

A steering committee monitors the progress and critical decisions of the transition to IFRS and continues to meet regularly. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources, and Operations. Quarterly updates are provided to the Audit and Risk Committee.

While IFRS uses a conceptual framework similar to Canadian GAAP and has many similarities to Canadian GAAP, there are several significant differences in accounting policies that must be addressed as part of our conversion project. Most differences are expected to have a relatively modest impact on our consolidated financial results. Based on the work we've completed to date, the more significant impacts of IFRS to us are as follows:

Property, Plant, and Equipment ("PP&E")

- <u>Key change in accounting</u>: Major inspection costs, which are currently expensed, will be capitalized and depreciated over the period until the next major inspection.
- <u>Income statement impact:</u> Earnings will likely be less volatile.
- <u>Balance sheet impact upon transition to IFRS:</u> Net increase in PP&E of approximately $115 million as previously expensed major inspection costs will be capitalized.
- <u>Cash flow statement impact</u>: Major inspection costs will be recorded as cash flows used in investing activities instead of as cash flows used in operating activities.
- <u>Other differences:</u> Additional disclosures reconciling the changes in cost and accumulated depreciation for individual classes of PP&E will be required.

Employee Benefits

- Key change in accounting: All actuarial gains and losses related to defined benefit plans will be recognized in other comprehensive income.
- Income statement impact: Expenses associated with defined benefit plans will differ. The impact on net earnings is not expected to be significant.
- Balance sheet impact upon transition to IFRS: Recognition of net cumulative actuarial losses of $78 million (after-tax) in opening retained earnings.
- Cash flow statement impact: None.

Joint Arrangements

- Key change in accounting: Prior to Dec. 31, 2010, the International Accounting Standards Board ("IASB") is expected to issue a new standard on the accounting for joint ventures, which is expected to come into effect Jan. 1, 2013, with early adoption permitted. If we decide to early adopt this new standard effective Jan. 1, 2010, certain joint arrangements that had been previously accounted for using proportionate consolidation will be accounted for using the equity method.
- Income statement impact: Revenues and expenses will be recorded as equity earnings or loss, a single line item on the Consolidated Statement of Earnings. There is no impact on net earnings.
- Balance sheet impact upon transition to IFRS: Our share of assets and liabilities will be removed from the various line items on the Statement of Financial Position and the corresponding net amount will be recorded as an investment.
- Cash flow statement impact: Our proportionate share of cash from equity accounted joint venture's will not be reflected on the Consolidated Statement of Cash Flow. Only contributions to and distributions from investments accounted for using the equity method will be reflected in the cash flow statement as an investing activity.

Provisions, Contingent Liabilities and Contingent Assets

- Key change in accounting: Asset retirement obligations ("AROs") are revalued at the end of each quarterly and annual reporting period using current market-based interest rates instead of using historic rates.
- Income statement impact: Accretion expense will be classified as a finance (interest) cost under IFRS as opposed to an operating expense under Canadian GAAP, and may fluctuate more often due to the impact of the period end revaluations.
- Balance sheet impact upon transition to IFRS: Due to differences in discount rates, the opening balance of the provisions for ARO will increase by approximately $34 million.
- Cash flow statement impact: None.

Arrangements Containing a Lease

- Key change in accounting: All contractual arrangements will be evaluated to determine if they contain a finance or operating lease.
- Income statement impact: For those contracts that are determined to be finance leases, a portion of payments received under the contract will be recorded as finance (interest) income. For those contracts that are determined to be operating leases, the timing of recognition of revenue may differ. The impact on net earnings in either case is not expected to be significant.
- Balance sheet impact of transitioning to IFRS: For certain long-term contracts that are deemed to be finance leases, the associated PP&E of $30 million will be removed from the Consolidated Balance Sheets and replaced with a long-term receivable of approximately $50 million, representing the present value of lease payments to be received over the life of the contract.
- Cash flow impact: Payments received under the contract for finance leases will be recorded as cash flows from financing activities instead of cash flows from operating activities.

Asset Impairment

- Key change in accounting: Asset impairment testing no longer utilizes undiscounted future cash flows to initially assess for impairment. Instead, an asset's carried value is compared to the greater of its value in use or fair value less normal costs to sell. Asset impairment charges can be reversed if the conditions creating the impairment reverse. The work associated with this standard is expected to be completed in the fourth quarter of 2010.
- Income statement impact: Depreciation expense for any impaired assets will be lower over the useful life of the asset.
- Balance sheet impact of transitioning to IFRS: Impairment charges will reduce PP&E and opening retained earnings.
- Cash flow impact: None.

Several exemptions from full retrospective application of certain IFRSs are available under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* to assist with the transition to IFRS. At present, we expect to make use of several exemptions that will have the following effect:

- Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax, of $63 million, will be reset to zero;
- Share-based payment guidance under IFRS will only be applied to equity instruments outstanding at transition that were granted on or after Nov. 7, 2002, and which had not vested by the transition date. The impact is not expected to be material;
- Business Combinations that occurred prior to Jan. 1, 2010 will continue to be measured and recorded at the Canadian GAAP amounts;
- We will use a simplified method to recalculate the cost of decommissioning assets included in PP&E;
- We will not adjust interest previously capitalized as part of PP&E under Canadian GAAP; and

In addition, various presentation changes are required under IFRS that have no impact on opening retained earnings.

At this time, it is not anticipated that any other material new standards or amendments will be effective on convergence in 2011. However, the progress and recommendations of IASB projects for financial instruments, post-employment benefits, financial statement presentation, revenue recognition, and leases are being closely monitored to ensure that any potential adverse impacts to the convergence project are identified and can be minimized.

NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under Canadian GAAP, and therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings or cash flow from operating activities, as determined in accordance with Canadian GAAP, 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.

Net Earnings Reconciliation

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Revenues	**700**	666	**2,008**	2,007
Fuel and purchased power	**320**	286	**871**	900
Gross margin	**380**	380	**1,137**	1,107
Operations, maintenance, and administration	**149**	144	**481**	525
Depreciation and amortization	**126**	111	**348**	346
Taxes, other than income taxes	**7**	5	**21**	17
Operating expenses	**282**	260	**850**	888
Operating income	**98**	120	**287**	219
Foreign exchange gain	**1**	1	**4**	4
Net interest expense	**(49)**	(36)	**(130)**	(102)
Other income	**-**	-	**-**	8
Earnings before non-controlling interests and income taxes	**50**	85	**161**	129
Non-controlling interests	**8**	3	**20**	27
Earnings before income taxes	**42**	82	**141**	102
Income tax expense (recovery)	**4**	16	**(15)**	-
Net earnings	**38**	66	**156**	102

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 2010, we excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

In calculating comparable earnings for 2009, we excluded the settlement of an outstanding commercial issue that was recorded in other income as this was related to our previously held Mexican equity investment. The change in life of certain component parts at Centralia Thermal was also excluded from the calculation of comparable earnings in 2009 as it relates to the cessation of mining activities at the Centralia coal mine and conversion of Centralia to consuming solely third party supplied coal.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Net earnings	**38**	66	**156**	102
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**(30)**	-
Settlement of commercial issue, net of tax	**-**	-	**-**	(6)
Change in life of Centralia parts, net of tax	**-**	-	**-**	1
Earnings on a comparable basis	**38**	66	**126**	97
Weighted average number of common shares outstanding in the period	**220**	198	**220**	198
Earnings on a comparable basis per share	**0.17**	0.34	**0.57**	0.49

EBITDA

Presenting 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	
	2010	2009	**2010**	2009
Operating income	**98**	120	**287**	219
Asset retirement obligation accretion per the Consolidated Statements of Cash Flows	**5**	5	**15**	17
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**130**	116	**362**	359
EBITDA	**233**	241	**664**	595

Funds from Operations and Cash Flow from Operating Activities per Share

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Funds from operations	**184**	178	**558**	463
Change in non-cash operating working capital balances	**46**	16	**(56)**	(129)
Cash flow from operating activities	**230**	194	**502**	334
Weighted average number of common shares outstanding in the period	**220**	198	**220**	198
Cash flow from operating activities per share	**1.05**	0.98	**2.28**	1.69

Free Cash Flow (Deficiency)

Free cash flow represents the amount of cash generated by our business that is available to invest in growth initiatives, repay scheduled principal repayments of recourse debt, pay additional common share dividends, or repurchase common shares.

Sustaining capital expenditures for the three months ended Sept. 30, 2010, represents total additions to PP&E per the Consolidated Statements of Cash Flows less $115 million ($113 million net of joint venture contributions) that we have invested in growth projects[2]. For the same period in 2009, we invested $154 million ($153 million net of joint venture contributions) in growth projects. For the nine months ended Sept. 30, 2010 and 2009, we invested $390 million ($383 million net of joint venture contributions) and $387 million ($378 million net of joint venture contributions), respectively, in growth projects.

(1) To calculate EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in cost of sales on the Consolidated Statements of Earnings and Retained Earnings.
(2) The calculation of sustaining capital expenditures for the three and nine months ended Sept. 30, 2010 also excludes the impact of project hedges.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Cash flow from operating activities	**230**	194	**502**	334
Add (Deduct):				
Sustaining capital expenditures	**(59)**	(116)	**(202)**	(294)
Cash dividends paid on common shares	**(49)**	(58)	**(169)**	(169)
Distributions paid to subsidiaries' non-controlling interests	**(15)**	(7)	**(44)**	(40)
Non-recourse debt repayments[1]	**-**	(1)	**(13)**	(19)
Other income	**-**	-	**-**	(8)
Free cash flow (deficiency)	**107**	12	**74**	(196)

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 2009	Q1 2010	Q2 2010	**Q3 2010**
Revenue	763	726	582	**700**
Net earnings	79	67	51	**38**
Basic and diluted earnings per share	0.37	0.31	0.23	**0.17**
Comparable earnings per share	0.40	0.31	0.10	**0.17**

	Q4 2008	Q1 2009	Q2 2009	Q3 2009
Revenue	808	756	585	666
Net earnings (loss)	94	42	(6)	66
Basic and diluted earnings (loss) per share	0.47	0.21	(0.03)	0.34
Comparable earnings (loss) per share	0.40	0.18	(0.03)	0.34

Basic and diluted earnings per share 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.

(1) Excludes debt repayments related to recourse debt that have been or will be refinanced with long-term debt issuances, consistent with our overall capital strategy.

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, 2010, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD LOOKING STATEMENTS

This MD&A, the documents incorporated herein by reference, and other reports and filings made with 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; expectations relating to the timing of the completion of the FEED study regarding CCS and the cost of the study; 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 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 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 2009 Annual Report and under the heading “Risk Factors” in our 2009 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

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2010**	2009	**2010**	2009
Revenues	**700**	666	**2,008**	2,007
Fuel and purchased power	**320**	286	**871**	900
	380	380	**1,137**	1,107
Operations, maintenance, and administration	**149**	144	**481**	525
Depreciation and amortization *(Note 22)*	**126**	111	**348**	346
Taxes, other than income taxes	**7**	5	**21**	17
	282	260	**850**	888
	98	120	**287**	219
Foreign exchange gain	**1**	1	**4**	4
Net interest expense *(Notes 5 and 12)*	**(49)**	(36)	**(130)**	(102)
Other income *(Note 3)*	**-**	-	**-**	8
Earnings before non-controlling interests and income taxes	**50**	85	**161**	129
Non-controlling interests *(Note 4)*	**8**	3	**20**	27
Earnings before income taxes	**42**	82	**141**	102
Income tax expense (recovery) *(Note 5)*	**4**	16	**(15)**	-
Net earnings	**38**	66	**156**	102
Retained earnings				
Opening balance	**625**	610	**634**	688
Common share dividends	**63**	58	**190**	172
Closing balance	**600**	618	**600**	618
Weighted average number of common shares outstanding in the period	**220**	198	**220**	198
Net earnings per share, basic and diluted	**0.17**	0.34	**0.71**	0.52

See accompanying notes.

TRANSALTA CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions of Canadian dollars)

	As At	
Unaudited	**Sept. 30, 2010**	Dec. 31, 2009
Cash and cash equivalents *(Note 6)*	**80**	82
Accounts receivable *(Notes 6 and 20)*	**361**	421
Collateral paid *(Notes 6 and 7)*	**32**	27
Prepaid expenses	**27**	18
Risk management assets *(Notes 6 and 7)*	**289**	144
Income taxes receivable *(Note 10)*	**53**	39
Inventory *(Note 8)*	**69**	90
Restricted cash *(Note 9)*	**7**	-
	918	821
Long-term receivables *(Note 10)*	**-**	49
Property, plant, and equipment		
Cost	**11,865**	11,721
Accumulated depreciation	**(4,076)**	(4,143)
	7,789	7,578
Goodwill *(Note 22)*	**432**	434
Intangible assets	**311**	333
Future income tax assets	**198**	234
Risk management assets *(Notes 6 and 7)*	**335**	224
Other assets *(Note 11)*	**112**	102
Total assets	**10,095**	9,775
Accounts payable and accrued liabilities *(Note 6)*	**406**	521
Collateral received *(Notes 6 and 7)*	**169**	86
Risk management liabilities *(Notes 6 and 7)*	**30**	45
Income taxes payable	**6**	10
Future income tax liabilities	**86**	45
Dividends payable	**65**	61
Current portion of long-term debt - recourse *(Notes 6 and 12)*	**235**	7
Current portion of long-term debt - non-recourse *(Notes 6 and 12)*	**21**	24
Current portion of asset retirement obligation *(Note 13)*	**39**	32
	1,057	831
Long-term debt - recourse *(Notes 6 and 12)*	**3,887**	3,857
Long-term debt - non-recourse *(Notes 6 and 12)*	**541**	554
Asset retirement obligation *(Note 13)*	**210**	250
Deferred credits and other long-term liabilities	**153**	136
Future income tax liabilities	**655**	662
Risk management liabilities *(Notes 6 and 7)*	**81**	78
Non-controlling interests *(Note 4)*	**439**	478
Shareholders' equity		
Common shares *(Notes 14 and 15)*	**2,194**	2,169
Retained earnings *(Note 15)*	**600**	634
Accumulated other comprehensive income *(Note 15)*	**278**	126
Total shareholders' equity	**3,072**	2,929
Total liabilities and shareholders' equity	**10,095**	9,775

Contingencies *(Notes 18 and 20)*
Commitments *(Notes 6 and 19)*
Subsequent events *(Note 25)*

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30 **2010**	2009	9 months ended Sept. 30 **2010**	2009
Net earnings	**38**	66	**156**	102
Other comprehensive income (loss)				
Losses on translating net assets of self-sustaining foreign operations	**(14)**	(96)	**(22)**	(158)
Gains on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1)	**8**	72	**10**	103
Gains on derivatives designated as cash flow hedges, net of tax(2)	**122**	11	**239**	225
Reclassification of losses (gains) on derivatives designated as cash flow hedges to balance sheet, net of tax(3)	**1**	-	**8**	(8)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(11)**	(38)	**(83)**	(95)
Other comprehensive income (loss)	**106**	(51)	**152**	67
Comprehensive income	**144**	15	**308**	169

(1) Net of income tax expense of 2 for the three and nine months ended Sept. 30, 2010 (2009 - 12 expense and 21 expense), respectively.

(2) Net of income tax expense of 64 and 124 for the three and nine months ended Sept. 30, 2010 (2009 - 2 recovery and 96 expense), respectively.

(3) Net of income tax expense of 1 and 3 for the three and nine months ended Sept. 30, 2010 (2009 - nil and 3 recovery), respectively.

(4) Net of income tax recovery of 8 and 43 for the three and nine months ended Sept. 30, 2010 (2009 - 21 recovery and 52 recovery), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2010**	2009	**2010**	2009
Operating activities				
Net earnings	**38**	66	**156**	102
Depreciation and amortization *(Note 22)*	**130**	116	**362**	359
Gain on sale of equipment	**-**	-	**(1)**	-
Non-controlling interests *(Note 4)*	**8**	3	**20**	27
Asset retirement obligation accretion *(Note 13)*	**5**	5	**15**	17
Asset retirement costs settled *(Note 13)*	**(12)**	(11)	**(27)**	(27)
Future income taxes	**2**	4	**19**	-
Unrealized foreign exchange loss (gain)	**2**	(4)	**-**	(15)
Unrealized loss (gain) from risk management activities	**2**	(1)	**2**	(1)
Other non-cash items	**9**	-	**12**	1
	184	178	**558**	463
Change in non-cash operating working capital balances *(Note 23)*	**46**	16	**(56)**	(129)
Cash flow from operating activities	**230**	194	**502**	334
Investing activities				
Additions to property, plant, and equipment	**(184)**	(269)	**(593)**	(681)
Proceeds on sale of property, plant, and equipment	**-**	4	**3**	5
Proceeds on sale of minority interest in Kent Hills *(Note 3)*	**-**	-	**-**	29
Increase in income tax recovered *(Note 10)*	**12**	-	**12**	-
Restricted cash	**(7)**	1	**(7)**	(1)
Realized losses on financial instruments	**(1)**	(2)	**(22)**	(16)
Net increase (decrease) in collateral received from counterparties	**60**	(15)	**86**	105
Net (increase) decrease in collateral paid to counterparties	**(4)**	2	**(6)**	9
Settlement of adjustments on sale of Mexican equity investment *(Note 3)*	**-**	-	**-**	(7)
Other	**(2)**	9	**4**	(5)
Cash flow used in investing activities	**(126)**	(270)	**(523)**	(562)
Financing activities				
Net (decrease) increase in credit facilities	**(15)**	182	**(44)**	300
Repayment of long-term debt	**(2)**	(2)	**(20)**	(20)
Issuance of long-term debt *(Note 12)*	**-**	-	**301**	200
Dividends paid on common shares *(Note 2)*	**(49)**	(58)	**(169)**	(169)
Net proceeds on issuance of common shares *(Notes 2 and 14)*	**-**	-	**1**	-
Realized gains (losses) on financial instruments	**9**	-	**(8)**	-
Distributions paid to subsidiaries' non-controlling interests	**(15)**	(7)	**(44)**	(40)
Other	**-**	(5)	**-**	(5)
Cash flow (used in) from financing activities	**(72)**	110	**17**	266
Cash flow from (used in) operating, investing, and financing activities	**32**	34	**(4)**	38
Effect of translation on foreign currency cash	**5**	(2)	**2**	(2)
Increase (decrease) in cash and cash equivalents	**37**	32	**(2)**	36
Cash and cash equivalents, beginning of period	**43**	54	**82**	50
Cash and cash equivalents, end of period	**80**	86	**80**	86
Cash taxes (recovered) paid	**(40)**	3	**(21)**	35
Cash interest paid	**42**	12	**96**	78

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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

1. ACCOUNTING POLICIES

These unaudited interim consolidated financial statements do not include all of the disclosures included in TransAlta Corporation's ("TransAlta" or "the Corporation") annual consolidated financial statements. Accordingly, these unaudited interim consolidated financial statements should be read in conjunction with the Corporation's most recent annual consolidated financial statements.

These unaudited interim consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of the results.

TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") using the same accounting policies as those used in the Corporation's most recent annual consolidated financial statements, except as explained below.

2. ACCOUNTING CHANGES

Current Accounting Changes

Inventory

During the second quarter, the Corporation modified its inventory measurement policy for commodity inventories held in its Energy Trading business segment to better reflect the nature of the underlying inventory and the segment's business objectives. Commodity inventories held in the Energy Trading segment are now measured at fair value less costs to sell, as opposed to the lower of cost and net realizable value. Changes in fair value less costs to sell are recognized in net earnings in the period of change. The effect of this change on current and prior periods was not material. Accordingly, the change has been applied prospectively and prior periods have not been restated.

Change in Estimate - Useful Lives

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, TransAlta's economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $7 million and $19 million for the three and nine months ended Sept. 30, 2010, respectively, compared to the same periods in 2009. The estimated annual pre-tax impact of this change is $29 million and will be reflected in depreciation expense and cost of goods sold.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

Future Accounting Changes

International Financial Reporting Standards ("IFRS") Convergence

In 2005, the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. On May 8, 2009, the AcSB re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that will be addressed as part of the convergence project, which have been more fully described in Note 2(D) to the Corporation's annual consolidated financial statements. During the third quarter of 2010, no new significant differences were identified.

The project is on track and is currently in the implementation phase with respect to dual reporting in 2010 and in the solution development and implementation phase with respect to 2011 full convergence. Cross-functional, issue-specific teams have been established to analyze the impacts of adopting IFRS, and focus on developing and implementing specific solutions for convergence.

A steering committee, comprised of senior representatives across the Corporation, has been established to monitor the progress and critical decisions in the transition to IFRS, and continues to meet regularly. Quarterly updates are provided to the Audit and Risk Committee. The Corporation is continuing to assess the impact of adopting these standards on the consolidated financial statements.

Comparative Figures

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

3. OTHER INCOME

During the second quarter of 2009, the Corporation sold a 17 per cent interest in its Kent Hills project to Natural Forces Technologies Inc. ("Natural Forces") for proceeds of $29 million, and recorded a pre-tax gain of $1 million. During the first quarter of 2009, the Corporation settled an outstanding commercial issue related to the sale of its Mexican equity investment for a pre-tax gain of $7 million.

4. NON-CONTROLLING INTERESTS

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2009	478
Distributions paid	(44)
Non-controlling interests portion of net earnings	20
Non-controlling interests portion of OCI	(15)
Balance, Sept. 30, 2010	**439**

5. INCOME TAX EXPENSE (RECOVERY)

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

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2010	2009	**2010**	2009
Current tax expense (recovery)	**2**	12	**(34)**	-
Future income tax expense	**2**	4	**19**	-
Income tax expense (recovery)	**4**	16	**(15)**	-

During the second quarter of 2010, TransAlta recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense also decreased by $14 million as a result of associated interest recoveries *(Note 12)*. $30 million of cash from the resolution of these tax matters was received during the third quarter and the balance is expected to be received before the end of the year.

6. 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. The "Financial Instruments and Hedges" section of Note 1(F) in the Corporation's 2009 annual consolidated financial statements describes how financial instruments are measured and how income and expenses, including fair value gains and losses, are recognized. The following table highlights the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Sept. 30, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	80	-	80
Accounts receivable	-	-	361	-	361
Collateral paid	-	-	32	-	32
Risk management assets					
Current	270	19	-	-	289
Long-term	332	3	-	-	335
Restricted cash	-	-	7	-	7
Financial liabilities			.		
Accounts payable and accrued liabilities	-	-	-	406	406
Collateral received	-	-	-	169	169
Risk management liabilities					
Current	11	19	-	-	30
Long-term	76	5	-	-	81
Long-term debt - recourse(1)	-	-	-	4,122	4,122
Long-term debt - non-recourse(1)	-	-	-	562	562

Carrying value of financial instruments as at Dec. 31, 2009

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	82	-	82
Accounts receivable	-	-	421	-	421
Collateral paid	-	-	27	-	27
Risk management assets					
Current	130	14	-	-	144
Long-term	219	5	-	-	224
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	521	521
Collateral received	-	-	-	86	86
Risk management liabilities					
Current	28	17	-	-	45
Long-term	75	3	-	-	78
Long-term debt - recourse(1)	-	-	-	3,864	3,864
Long-term debt - non-recourse(1)	-	-	-	578	578

(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.

I. 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 Energy Trading(1) 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 using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly or indirectly.

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets 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 upon observable commodity futures curves and derivatives with input 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.

In limited circumstances, Energy Trading 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

(1) The Energy Trading segment was referred to as "Commercial Operations and Development" in 2009.

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.

As a result of the acquisition of Canadian Hydro Developers, Inc., 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 modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

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.

Energy Trading

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, 2010:

	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, 2009	-	297	(27)	-	-	1	-	297	(26)
Changes attributable to:									
Market price changes on existing contracts	-	227	21	9	(2)	-	9	225	21
Market price changes on new contracts	-	73	-	(6)	(3)	(1)	(6)	70	(1)
Contracts settled	-	(96)	(3)	(1)	2	-	(1)	(94)	(3)
Change in foreign exchange rates	-	(3)	-	-	-	-	-	(3)	-
Transfers in/out of Level III	-	1	(1)	-	-	-	-	1	(1)
Net risk management assets (liabilities) at Sept. 30, 2010	-	**499**	**(10)**	**2**	**(3)**	**-**	**2**	**496**	**(10)**
Additional Level III gain information:									
Change in fair value included in OCI			17			-			17
Realized gain included in earnings before income taxes			3			-			3
Unrealized gain (loss) included in earnings before income taxes relating to those net assets held at Sept. 30, 2010			-			(1)			(1)

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, 2010 is estimated to be +/- $18 million (Dec. 31, 2009 – $24 million). Where an internally-developed fundamental price forecast is used, reasonably 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 reasonably alternate fundamental price forecasts unavailable.

The total change in Level III financial assets and liabilities held at Sept. 30, 2010, that was recognized in pre-tax earnings for the nine months ended Sept. 30, 2010 was $2 million (Sept. 30, 2009 - $1 million).

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

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	57	244	163	40	10	(15)	**499**
	Level III	2	6	2	1	-	(21)	**(10)**
Non-hedges	Level I	2	-	-	-	-	-	**2**
	Level II	1	(4)	(1)	5	-	(4)	**(3)**
	Level III	-	-	-	-	-	-	**-**
Total by level	Level I	2	-	-	-	-	-	**2**
	Level II	58	240	162	45	10	(19)	**496**
	Level III	2	6	2	1	-	(21)	**(10)**
Total net assets (liabilities)		**62**	**246**	**164**	**46**	**10**	**(40)**	**488**

Other Risk Management Assets and Liabilities

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, 2010:

	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 liabilities at Dec. 31, 2009	-	(24)	-	-	(2)	-	-	(26)	-
Changes attributable to:									
Market price changes on existing contracts	-	19	-	-	-	-	-	19	-
Market price changes on new contracts	-	10	-	-	(1)	-	-	9	-
Contracts settled	-	21	-	-	2	-	-	23	-
Net risk management assets (liabilities) at Sept. 30, 2010	**-**	**26**	**-**	**-**	**(1)**	**-**	**-**	**25**	**-**

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. For hedges that remain effective and qualify for hedge accounting, any change in value will be deferred in Accumulated Other Comprehensive Income ("AOCI") until the instrument is settled, or until such time as the hedged item affects net earnings, or there is a reduction in the net investment in the foreign operations.

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

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	-
	Level II	(5)	3	1	4	(1)	24	26
	Level III	-	-	-	-	-	-	-
Non-hedges	Level I	-	-	-	-	-	-	-
	Level II	(1)	-	-	-	-	-	(1)
	Level III	-	-	-	-	-	-	-
Total by level	Level I	-	-	-	-	-	-	-
	Level II	(6)	3	1	4	(1)	24	25
	Level III	-	-	-	-	-	-	-
Total net (liabilities) assets		**(6)**	**3**	**1**	**4**	**(1)**	**24**	**25**

The fair value of the Corporation's long-term debt is outlined below:

	Fair value(1)				Total carrying value
As at Sept. 30, 2010	**Level I**	**Level II**	**Level III**	**Total**	
Financial assets and liabilities measured at other than fair value					
Long-term debt - Sept. 30, 2010(2)	-	4,968	-	4,968	4,684
Long-term debt - Dec. 31, 2009(2)	-	4,499	-	4,499	4,442

(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, restricted cash, accounts receivable, collateral paid, accounts payable and accrued liabilities, and collateral received).

(2) Includes current portion.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives have been determined using valuation techniques or models.

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 Consolidated Balance Sheets 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, 2010**	Dec. 31, 2009
Unamortized (loss) gain at beginning of period	**(1)**	2
New inception gains (losses)	**2**	(1)
Amortization recorded in net earnings during the period	**(1)**	(2)
Unamortized loss at end of period	**-**	(1)

7. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	Sept. 30, 2010					Dec. 31, 2009
	Net Investment Hedges	**Cash Flow Hedges**	**Fair Value Hedges**	**Not Designated as a Hedge**	**Total**	Total
Risk management assets						
Energy Trading						
Current	-	267	-	19	286	144
Long-term	-	288	-	3	291	207
Total Energy Trading risk management assets	-	555	-	22	577	351
Other						
Current	-	3	-	-	3	-
Long-term	-	-	44	-	44	17
Total other risk management assets	-	3	44	-	47	17
Risk management liabilities						
Energy Trading						
Current	-	6	-	18	24	30
Long-term	-	60	-	5	65	50
Total Energy Trading risk management liabilities	-	66	-	23	89	80
Other						
Current	5	-	-	1	6	15
Long-term	-	16	-	-	16	28
Total other risk management liabilities	5	16	-	1	22	43
Net Energy Trading risk management assets (liabilities)	**-**	**489**	**-**	**(1)**	**488**	271
Net other risk management (liabilities) assets	**(5)**	**(13)**	**44**	**(1)**	**25**	(26)
Net total risk management (liabilities) assets	**(5)**	**476**	**44**	**(2)**	**513**	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, 2009 – U.S.$1,100 million), and a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2009 – U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in self-sustaining foreign operations.

The Corporation has also hedged a portion of its net investment in self-sustaining foreign operations with cross-currency swaps and foreign currency forward sales (purchase) contracts as shown below:

Cross-Currency Swap

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

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
-	**-**	**-**	AUD34	(2)	2010

Foreign Currency Contracts

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

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD180	**(2)**	**2010**	AUD120	(2)	2010
U.S.13	**(3)**	**2010**	U.S.(182)	(1)	2010

ii. Effect on the Consolidated Statements of Comprehensive Income

For the three months ended Sept. 30, 2010, a net after-tax loss of $6 million (Sept. 30, 2009 – loss of $24 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in Other Comprehensive Income ("OCI"). For the nine months ended Sept. 30, 2010, a net after-tax loss of $12 million (Sept. 30, 2009 – loss of $55 million), relating to the translation of the Corporation's net investment in self-sustaining 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 Consolidated Statements of Comprehensive Income for the three and nine months ended Sept. 30, 2010 and 2009:

Financial instruments in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI for the 3 months ended Sept. 30, 2010**	Pre-tax gain (loss) recognized in OCI for the 3 months ended Sept. 30, 2009
Long-term debt	**26**	101
Cross currency	**-**	(1)
Foreign exchange	**(16)**	(16)
OCI impact	**10**	84

Financial instruments in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI for the 9 months ended Sept. 30, 2010**	Pre-tax gain (loss) recognized in OCI for the 9 months ended Sept. 30, 2009
Long-term debt	**35**	185
Cross currency	**3**	(4)
Foreign exchange	**(26)**	(57)
OCI impact	**12**	124

b. Cash flow hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at Sept. 30, 2010, were as follows:

(Thousands)	Sept. 30, 2010		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	35,217	11	28,989	-
Natural gas (GJ)	485	33,719	2,163	360
Oil (gallons)	-	16,254	-	25,074

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:

Sept. 30, 2010				Dec. 31, 2009			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
222	U.S.205	(5)	2010-2017	91	U.S.78	(8)	2010
U.S.3	3	-	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:

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset	Maturity
U.S.300	1	2012	-	-	-
U.S.300	2	2013	-	-	-

Cross-Currency Swap

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

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.500	(11)	2015	U.S.500	(16)	2015

iii. Interest Rate Risk Management

The Corporation also had outstanding forward start interest rate swaps that converted floating rate debt into fixed rate debt with fixed rates ranging from 3.5 per cent to 4.6 per cent. 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.

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
-	-	-	U.S.300	(8)	2020

iv. Effect on the Consolidated Statements of Comprehensive Income

Forward sale and purchase commodity contracts, foreign exchange contracts, cross-currency 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 Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets for the three and nine months ended Sept. 30, 2010 and 2009:

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 recognized in earnings**	**Pre-tax gain recognized in earnings**
Commodity	**212**	Revenue	**(46)**	Revenue	**-**
Foreign exchange (loss) on project hedges	**(6)**	Property, plant, and equipment	**2**	Interest expense	**1**
Foreign exchange (loss) on U.S.debt	**(10)**	Foreign exchange loss on U.S.debt	**26**		
Cross-currency swaps	**(10)**	Interest expense	**1**		
Interest rate	**-**				
OCI impact	**186**	**OCI impact**	**(17)**	**Net earnings impact**	**1**

3 months ended Sept. 30, 2009

Effective portion				Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax (loss) gain recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of loss recognized in earnings	Pre-tax gain (loss) recognized in earnings
Commodity	(24)	Revenue	(60)	Revenue	2
Foreign exchange (loss) on project hedges	(25)	Property, plant, and equipment	-	Interest expense	(1)
Cross-currency swaps	-	Interest expense	1		
Interest rate	58				
OCI impact	9	OCI impact	(59)	Net earnings impact	1

9 months ended Sept. 30, 2010

Derivatives in cash flow hedging relationships	**Effective portion** Pre-tax gain (loss) recognized in OCI	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Ineffective portion** Location of loss recognized in earnings	**Pre-tax loss recognized in earnings**
Commodity	**372**	Revenue	**(134)**	Revenue	**-**
Foreign exchange gain (loss) on project hedges	**(7)**	Property, plant, and equipment	**11**	Interest expense	**-**
Foreign exchange loss on U.S.debt	**-**	Foreign exchange loss on U.S.debt	**7**		
Cross-currency swaps	**7**	Interest expense	**1**		
Interest rate	**(9)**				
OCI impact	**363**	**OCI impact**	**(115)**	**Net earnings impact**	**-**

9 months ended Sept. 30, 2009

Derivatives in cash flow hedging relationships	Effective portion Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Ineffective portion Location of loss recognized in earnings	Pre-tax loss recognized in earnings
Commodity	312	Revenue	(148)	Revenue	-
Foreign exchange loss on project hedges	(15)	Property, plant, and equipment	(11)	Interest expense	(2)
Cross-currency swaps	-	Interest expense	1		
Interest rate	24				
OCI impact	321	OCI impact	(158)	Net earnings impact	(2)

Over the next 12 months, the Corporation estimates that $174 million (Dec. 31, 2009 – $77 million after-tax gains) of after-tax gains will be reclassified from AOCI and recognized in net earnings.

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 6.9 per cent, to floating rate debt through interest rate swaps as shown below:

Sept. 30, 2010 Notional amount	**Fair value asset**	**Maturity**	Dec. 31, 2009 Notional amount	Fair value asset (liability)	Maturity
100	**3**	**2011**	100	7	2011
U.S.100	**4**	**2013**	U.S.50	(1)	2013
U.S.300	**37**	**2018**	U.S.150	7	2018

Including the interest rate swaps above, 33 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2009 – 31 per cent).

ii. Effect on the Consolidated Statements of Comprehensive Income

No ineffective portion of fair value hedges was recorded for the three and nine months ended Sept. 30, 2010 and 2009.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings for the three and nine months ended Sept. 30, 2010 and 2009:

Derivatives in fair value hedging relationships	**Location of gain (loss) on statements of earnings**	**3 months ended Sept. 30**		**9 months ended Sept. 30**	
		2010	2009	**2010**	2009
Interest rate contracts	Interest expense	**6**	(1)	**33**	13
Long-term debt	Interest expense	**(6)**	1	**(33)**	(13)
Net earnings impact		**-**	-	**-**	-

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 where 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 hedging 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 reported as revenue in the period the change occurs. The Corporation's outstanding Energy Trading derivative instruments that are not designated as hedging instruments at Sept. 30, 2010, were as follows:

(Thousands)	**Sept. 30, 2010**		Dec. 31, 2009	
Type	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**17,185**	**18,461**	14,107	14,844
Natural gas (GJ)	**659,293**	**675,908**	323,793	309,764
Transmission (MWh)	**-**	**2,587**	-	4,852

b. Cross-Currency Swaps

Cross-currency 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 swap is as follows:

Sept. 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value 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:

Sept. 30, 2010				Dec. 31, 2009			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
AUD7	**6**	**-**	**2010**	-	-	-	-
AUD4	**U.S.3**	**(1)**	**2010**	-	-	-	-
U.S.35	**37**	**-**	**2010**	U.S.13	14	-	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 Consolidated Statements of Comprehensive Income

The tables below summarizes the net realized and unrealized gains and losses included in net earnings that are associated with derivatives not designated as hedges:

	3 months ended Sept. 30					
	2010			2009		
	Net unrealized losses	**Net realized gains (losses)**	**Total**	Net unrealized gains	Net realized (losses) gains	Total
Commodity	**(4)**	**5**	**1**	1	(1)	-
Foreign exchange	**(1)**	**(4)**	**(5)**	-	3	3
Other	**(2)**	**(1)**	**(3)**	-	-	-

	9 months ended Sept. 30					
	2010			2009		
	Net unrealized losses	**Net realized gains (losses)**	**Total**	Net unrealized gains	Net realized gains (losses)	Total
Commodity	**(4)**	**11**	**7**	2	33	35
Interest	**-**	**-**	**-**	-	(1)	(1)
Foreign exchange	**-**	**-**	**-**	4	(2)	2
Other	**-**	**(1)**	**(1)**	-	(1)	(1)

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk – Proprietary Energy Trading

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. Value at Risk ("VaR") at Sept. 30, 2010 associated with the Corporation's proprietary energy trading activities was $4 million (Dec. 31, 2009 – $3 million).

b. Commodity Price Risk - Generation

VaR at Sept. 30, 2010 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $21 million (Dec. 31, 2009 – $45 million).

The Corporation's policy on asset-backed transactions is to seek normal purchase / normal sale ("NPNS") contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or 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, 2010 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was nil (Dec. 31, 2009 – nil).

c. Interest Rate Risk

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 at the balance sheet date, 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			
	2010		2009	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]
50 basis point change	5	-	3	(8)

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

d. Currency Rate Risk

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 at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent 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			
	2010		2009	
Currency	**Net earnings decrease**[1]	**OCI gain**[1,2]	Net earnings decrease[1]	OCI gain[1,2]
U.S.	(4)	8	(1)	2
AUD	(1)	-	(2)	-
Total	**(5)**	**8**	(3)	2

(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

At Sept. 30, 2010, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at the end of the period.

The Corporation's maximum exposure to credit risk at Sept. 30, 2010 and at Dec. 31, 2009, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. 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 and including the fair value of open trading, net of any collateral held, at Sept. 30, 2010 was $56 million (Dec. 31, 2009 – $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, 2010:

	Investment grade %	Non-investment grade %	Total %
Accounts receivable	95	5	100
Risk management assets	100	-	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, 2010	Dec. 31, 2009
Allowance at beginning of period	**49**	57
Change in foreign exchange rates	**(1)**	(8)
Allowance at end of period	**48**	49

At Sept. 30, 2010, the Corporation did not have any significant past due trade receivables except as disclosed in Note 20.

III. Liquidity Risk

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

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Accounts payable and accrued liabilities	406	-	-	-	-	-	406
Collateral received	169	-	-	-	-	-	169
Debt(1)	11	253	1,044	647	231	2,491	4,677
Energy Trading risk management (assets) liabilities(2)	(62)	(246)	(164)	(46)	(10)	40	(488)
Other risk management liabilities (assets)(2)	6	(3)	(1)	(4)	1	(24)	(25)
Interest on long-term debt	72	265	238	212	180	1,141	2,108
Total	**602**	**269**	**1,117**	**809**	**402**	**3,648**	**6,847**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.

(2) Net risk management assets and liabilities as above.

C. Collateral

I. Financial Assets Provided as Collateral

At Sept. 30, 2010, $56 million (Dec. 31, 2009 – $45 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Generation, LLC ("CE Gen") have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

At Sept. 30, 2010, the Corporation provided $32 million (Dec. 31, 2009 – $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, 2010, the Corporation received $169 million (Dec. 31, 2009 – $86 million) in cash collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its 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, 2010 the Corporation had posted collateral of $19 million (Dec. 31, 2009 - $37 million) in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at Sept. 30, 2010, the Corporation would be required to post an additional $19 million of collateral to its counterparties.

8. INVENTORY

Inventory held in the normal course of business which includes coal, emission credits, and natural gas are valued at the lower of cost and net realizable value. Inventory held for commodity trading, which also includes natural gas, is valued at fair value less costs to sell *(Note 2)*. The classifications are as follows:

As at	**Sept. 30, 2010**	Dec. 31, 2009
Coal	**62**	86
Natural gas	**7**	4
Total	**69**	90

The decrease in coal inventory at Sept. 30, 2010 compared to Dec. 31, 2009 is primarily due to higher production at the coal facilities.

The change in inventory is outlined below:

Balance, Dec. 31, 2009	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, 2010, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

9. RESTRICTED CASH

Restricted cash relates to cash held in a separate bank account maintained by CE Gen pursuant to certain non-recourse debt arrangements.

10. LONG-TERM RECEIVABLE

In 2008, the Corporation was reassessed by taxation authorities in Canada related 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 the third quarter, a decision from Tax Court was received which allowed for the recovery of $38 million of the previously paid taxes and interest. A $12 million refund of tax and interest was received during the third quarter and the balance is expected to be received in the fourth quarter or in early 2011. TransAlta filed an appeal with the Federal Court in September.

11. OTHER ASSETS

The components of other assets are as follows:

As at	**Sept. 30, 2010**	Dec. 31, 2009
Deferred license fees	**23**	22
Accrued pension benefit asset	**23**	18
Project development costs	**48**	45
Keephills 3 transmission deposit	**8**	8
Other	**10**	9
Total other assets	**112**	102

12. LONG-TERM DEBT AND NET INTEREST EXPENSE

The amounts outstanding are as follows:

As at	Sept. 30, 2010			Dec. 31, 2009		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**1,014**	**1,014**	**1.5%**	1,063	1,063	1.0%
Debentures	**1,057**	**1,076**	**6.7%**	1,055	1,076	6.7%
Senior notes[3]	**1,997**	**1,957**	**6.0%**	1,687	1,684	5.9%
Non-recourse	**562**	**576**	**6.5%**	578	581	6.3%
Other	**54**	**54**	**6.7%**	59	59	6.7%
	4,684	**4,677**		4,442	4,463	
Less: current portion	**256**	**253**		31	31	
Total long-term debt	**4,428**	**4,424**		4,411	4,432	

(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) 2010 - U.S.$1,900 million, 2009 - $1,600 million.

On March 12, 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040.

The components of net interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Interest on debt	**63**	46	**181**	132
Interest income *(Note 5)*	**(1)**	(3)	**(16)**	(6)
Capitalized interest	**(13)**	(10)	**(35)**	(27)
Other	**-**	3	**-**	3
Net interest expense	**49**	36	**130**	102

The Corporation capitalizes interest during the construction phase of growth capital projects.

13. ASSET RETIREMENT OBLIGATIONS

The change in the asset retirement obligation balances is summarized below:

Balance, Dec. 31, 2009	282
Liabilities incurred in period	2
Liabilities settled in period	(27)
Accretion expense	15
Revisions in estimated cash flows	(21)
Change in foreign exchange rates	(2)
	249
Less: current portion	39
Balance, Sept. 30, 2010	**210**

Revisions in estimated cash flows are primarily due to changes in the estimates associated with the decommissioning of the Wabamun plant, which was shut down on March 31, 2010.

14. COMMON SHARES ISSUED AND OUTSTANDING

A. Issued and outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. At Sept. 30, 2010, the Corporation had 219.5 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended Sept. 30, 2010, 0.7 million (Sept. 30, 2009 – 0.1 million) common shares were issued for $15 million (Sept. 30, 2009 – nil). During the nine months ended Sept. 30, 2010, 1.1 million (Sept. 30, 2009 – 0.3 million) common shares were issued for $19 million (Sept. 30, 2009 – nil).

During 2010, no shares were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program prior its expiry on May 6, 2010. During the three and nine months ended Sept. 30, 2009, no shares were acquired or cancelled under the NCIB program.

B. Stock options

At Sept. 30, 2010, the Corporation had 2.3 million outstanding employee stock options (Dec. 31, 2009 – 1.5 million), reflecting 0.9 million stock options granted on Feb. 1, 2010, at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2011 and expire after 10 years. During the three months ended Sept. 30, 2010, a nominal number of options expired, or were exercised or cancelled (Sept. 30, 2009 – nil). During the nine months ended Sept. 30, 2010, 0.1 million options expired, or were exercised or cancelled (Sept. 30, 2009 – 0.1 million expired, 0.1 million cancelled).

The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model and the following assumptions, resulting in a fair value of $3.67 per option:

Risk free interest rate (%)	2.5
Expected life of the options (years)	4.9
Expected annual dividend yield (%)	5.1
Volatility in the price of the Corporation's shares (%)	29.7

For the three and nine months ended Sept. 30, 2010, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was $1 million (Sept. 30, 2009 - nil), and $2 million (Sept. 30, 2009 - $1 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. During the three and nine months ended Sept. 30, 2010, the Corporation issued 0.7 million and 0.9 million common shares for $15 million and $18 million, respectively. 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.

15. SHAREHOLDERS' EQUITY

A reconciliation of shareholders' equity is as follows:

	Common shares	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
Balance, Dec. 31, 2009	2,169	634	126	2,929
Net earnings	-	156	-	156
Common shares issued	25	-	-	25
Dividends declared	-	(190)	-	(190)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	-	-	(12)	(12)
Gains on derivatives designated as cash flow hedges, net of tax	-	-	239	239
Derivatives designated as cash flow hedges in prior periods transferred to the Consolidated Balance Sheets and net earnings in the current period, net of tax	-	-	(75)	(75)
Balance, Sept. 30, 2010	**2,194**	**600**	**278**	**3,072**

The components of AOCI are presented below:

As at	Sept. 30, 2010	Dec. 31, 2009
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and of tax	**(75)**	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	**353**	189
Total accumulated other comprehensive income	**278**	126

16. CAPITAL

TransAlta's capital is comprised of the following:

As at	Sept. 30, 2010	Dec. 31, 2009	Increase/ (decrease)
Current portion of long-term debt	**256**	31	225
Less: cash and cash equivalents	**(80)**	(82)	2
	176	(51)	227
Long-term debt			
Recourse	**3,887**	3,857	30
Non-recourse	**541**	554	(13)
Non-controlling interests	**439**	478	(39)
Shareholders' equity			
Common shares	**2,194**	2,169	25
Retained earnings	**600**	634	(34)
AOCI	**278**	126	152
	7,939	7,818	121
Total capital	**8,115**	7,767	348

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2009.

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, 2010	Dec. 31, 2009	Target
Cash flow to interest coverage (times)(1)	**4.6**	4.9	4 to 5 times
Cash flow to debt (%)(1)	**21.2**	20.1	20 to 25 per cent
Debt to invested capital (%)	**56.7**	56.1	55 to 60 per cent

(1) Last 12 months.

For the three and nine months ended Sept. 30, 2010 and 2009, net cash outflows from operating activities, after cash dividends and capital asset additions, are summarized below:

	3 months ended Sept. 30			**9 months ended Sept. 30**		
	2010	2009	Favourable/ (Unfavourable)	**2010**	2009	Favourable/ (Unfavourable)
Cash flow from operating activities	**230**	194	36	**502**	334	168
Cash dividends paid	**(49)**	(58)	9	**(169)**	(169)	-
Capital asset expenditures	**(184)**	(269)	85	**(593)**	(681)	88
Net cash outflow	**(3)**	(133)	130	**(260)**	(516)	256

For the three months ended Sept. 30, 2010, the increase in the net cash flows relative to the third quarter of 2009 resulted primarily from lower capital expenditures and higher cash flow from operating activities. For the nine months ended Sept. 30, 2010, the increase in the net cash flows relative to the same period in 2009 resulted primarily from higher cash flow from operating activities and lower capital expenditures. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business.

The financial terms and conditions of the Corporation's credit facilities remain unchanged from Dec. 31, 2009.

TransAlta's formal dividend policy has remained unchanged from Dec. 31, 2009.

17. RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Sept. 30, 2010, TAGP had received $59 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TransAlta Cogeneration, L.P. ("TA Cogen"), which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. The notional gas volume in the swap transaction is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

18. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings which 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. Although there can be no assurance that any particular claim will be resolved in the Corporation's favour, 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.

19. COMMITMENTS

Sundance Unit 3 Uprate

On Sept. 13, 2010, TransAlta obtained approval from the Board of Directors for a 15 megawatt ("MW") efficiency uprate at Unit 3 of its Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Kent Hills Expansion

On Jan. 11, 2010, TransAlta announced that it had been awarded a 25-year contract to provide an additional 54 MW of wind power to New Brunswick Power. Under the agreement, TransAlta will expand the existing 96 MW Kent Hills wind facility to a total of 150 MW. The total capital cost of the project is estimated to be $100 million, with $78 million incurred to date, and is expected to begin commercial operations by the end of 2010. Natural Forces will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

20. PRIOR PERIOD REGULATORY DECISION

With respect to refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange and the California Independent System Operator, the California Parties have sought rehearing of the Federal Energy Regulatory Commission's ("FERC") refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. In a decision issued Aug. 24, 2007, which denied rehearing remanded matters to FERC, the Ninth Circuit ruled that FERC had properly excluded both the Summer Transactions and the CERS Transactions from the complaint proceeding. FERC has yet to respond to the remand.

21. 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 Consolidated Balance Sheets. 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, 2010 totalled $332 million (Dec. 31, 2009 - $334 million) with nil (Dec. 31, 2009 – nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.1 billion (Dec. 31, 2009 – $2.1 billion) of committed credit facilities of which $0.8 billion (Dec. 31, 2009 – $0.7 billion) is not drawn, and is available as of Sept. 30, 2010, subject to customary borrowing conditions.

In addition to the $0.8 billion available under the credit facilities, TransAlta also has $80 million of cash.

22. SEGMENTED DISCLOSURES

A. Each business segment assumes responsibility for its operating results measured as operating income or loss.

3 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Revenues	697	3	-	700
Fuel and purchased power	320	-	-	320
	377	3	-	380
Operations, maintenance, and administration	131	4	14	149
Depreciation and amortization	121	-	5	126
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation (recovery)	1	(1)	-	-
	260	3	19	282
	117	-	(19)	98
Foreign exchange gain				1
Net interest expense *(Notes 5 and 12)*				(49)
Earnings before non-controlling interests and income taxes				50

3 months ended Sept. 30, 2009	Generation	Energy Trading	Corporate	Total
Revenues	659	7	-	666
Fuel and purchased power	286	-	-	286
	373	7	-	380
Operations, maintenance, and administration	116	9	19	144
Depreciation and amortization	106	1	4	111
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation (recovery)	8	(8)	-	-
	235	2	23	260
	138	5	(23)	120
Foreign exchange gain				1
Net interest expense *(Note 12)*				(36)
Earnings before non-controlling interests and income taxes				85

9 months ended Sept. 30, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,991**	**17**	**-**	**2,008**
Fuel and purchased power	**871**	**-**	**-**	**871**
	1,120	**17**	**-**	**1,137**
Operations, maintenance, and administration	**419**	**12**	**50**	**481**
Depreciation and amortization	**333**	**1**	**14**	**348**
Taxes, other than income taxes	**21**	**-**	**-**	**21**
Intersegment cost allocation (recovery)	**4**	**(4)**	**-**	**-**
	777	**9**	**64**	**850**
	343	**8**	**(64)**	**287**
Foreign exchange gain				**4**
Net interest expense *(Notes 5 and 12)*				**(130)**
Earnings before non-controlling interests and income taxes				**161**

9 months ended Sept. 30, 2009	Generation	Energy Trading	Corporate	Total
Revenues	1,970	37	-	2,007
Fuel and purchased power	900	-	-	900
	1,070	37	-	1,107
Operations, maintenance, and administration	434	25	66	525
Depreciation and amortization	330	2	14	346
Taxes, other than income taxes	17	-	-	17
Intersegment cost allocation (recovery)	24	(24)	-	-
	805	3	80	888
	265	34	(80)	219
Foreign exchange gain				4
Net interest expense *(Note 12)*				(102)
Other income *(Note 3)*				8
Earnings before non-controlling interests and income taxes				129

For the three months ended Sept. 30, 2010 and 2009, included above in Generation is $4 million and $1 million of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects, respectively. For the nine months ended Sept. 30, 2010 and 2009, incentives of $13 million and $5 million, respectively, were included above in Generation.

The intersegment cost allocation (recovery) decreased for the three and nine months ended Sept. 30, 2010 as a result of costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010.

B. Selected Consolidated Balance Sheets information

As at Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Goodwill	**402**	**30**	**-**	**432**
Total segment assets	**9,489**	**119**	**487**	**10,095**

As at Dec. 31, 2009				
Goodwill	404	30	-	434
Total segment assets	9,133	148	494	9,775

A change in foreign exchange rates resulted in a $2 million decrease in goodwill in a self-sustaining foreign operation.

C. Selected Consolidated Cash Flow information

3 months ended Sept. 30, 2010	Generation	Energy Trading	Corporate	Total
Capital expenditures	**175**	**-**	**9**	**184**

3 months ended Sept. 30, 2009				
Capital expenditures	262	2	5	269

9 months ended Sept. 30, 2010	Generation	Trading	Corporate	Total
Capital expenditures	**570**	**-**	**23**	**593**

9 months ended Sept. 30, 2009				
Capital expenditures	664	3	14	681

D. Depreciation and amortization on the Consolidated Statements of Cash Flows

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Depreciation and amortization expense on the Consolidated Statements of Earnings	**126**	111	**348**	346
Depreciation included in fuel and purchased power	**9**	9	**28**	29
Accretion expense included in depreciation and amortization expense	**(5)**	(5)	**(15)**	(17)
Other	**-**	1	**1**	1
Depreciation and amortization on the Consolidated Statements of Cash Flows	**130**	116	**362**	359

23. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended Sept. 30		9 months ended Sept. 30	
	2010	2009	**2010**	2009
Source (use):				
Accounts receivable	**7**	(64)	**61**	150
Prepaid expenses	**(2)**	1	**(8)**	(7)
Income taxes receivable	**49**	4	**(10)**	(35)
Inventory	**28**	(3)	**19**	(42)
Accounts payable and accrued liabilities	**(36)**	71	**(114)**	(191)
Income taxes payable	**-**	7	**(4)**	(4)
Change in non-cash operating working capital	**46**	16	**(56)**	(129)

24. EMPLOYEE FUTURE BENEFITS

Costs recognized in the period are presented below:

3 months ended Sept. 30, 2010	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**1**	**-**	**-**	**1**
Interest cost	**5**	**-**	**1**	**6**
Actual return on plan assets	**(5)**	**-**	**-**	**(5)**
Actuarial loss	**1**	**1**	**1**	**3**
Amortization of net transition asset	**(3)**	**-**	**-**	**(3)**
Defined benefit (income) expense	**(1)**	**1**	**2**	**2**
Defined contribution expense	**5**	**-**	**-**	**5**
Net expense	**4**	**1**	**2**	**7**

3 months ended Sept. 30, 2009	Registered	Supplemental	Other	Total
Current service cost	-	-	1	1
Interest cost	6	1	-	7
Actual return on plan assets	(4)	-	-	(4)
Actuarial loss	1	-	-	1
Amortization of net transition asset	(3)	-	-	(3)
Defined benefit expense	-	1	1	2
Defined contribution expense	4	-	-	4
Net expense	4	1	1	6

9 months ended Sept. 30, 2010	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**2**	**1**	**1**	**4**
Interest cost	**15**	**2**	**2**	**19**
Actual return on plan assets	**(15)**	**-**	**-**	**(15)**
Actuarial loss	**3**	**1**	**1**	**5**
Amortization of net transition asset	**(7)**	**-**	**-**	**(7)**
Defined (income) benefit expense	**(2)**	**4**	**4**	**6**
Defined contribution expense	**15**	**-**	**-**	**15**
Net expense	**13**	**4**	**4**	**21**

9 months ended Sept. 30, 2009	Registered	Supplemental	Other	Total
Current service cost	2	1	1	4
Interest cost	17	3	1	21
Actual return on plan assets	(14)	-	-	(14)
Actuarial loss	2	-	-	2
Amortization of net transition asset	(7)	-	-	(7)
Defined benefit expense	-	4	2	6
Defined contribution expense	14	-	-	14
Net expense	14	4	2	20

25. SUBSEQUENT EVENTS

Sundance Unit 3 Outage

On Oct. 20, 2010, the Balancing Pool confirmed it agreed with TransAlta's determination that the mechanical failure sustained in the second quarter at its 353 MW Sundance Unit 3 meets the requirements of a High Impact Low Probability event under the Power Purchase Arrangement. While this determination does not constitute a Force Majeure event, nor provides a definitive resolution to the dispute, management believes this strengthens the Corporation's position with regards to final protection from the event remains confident this will be confirmed in due course. This unit continues to operate at a reduced capacity level and no assurance can be given as to whether it will return to normal operating levels prior to the completion of major maintenance currently scheduled for the middle of 2012.

SUPPLEMENTAL INFORMATION

		Sept. 30, 2010	Dec. 31, 2009
Closing market price (TSX) ($)		**21.96**	23.48
Price range for the last 12 months (TSX) ($)	High	**23.98**	25.30
	Low	**19.61**	18.11
Debt to invested capital including non recourse debt (%)		**56.7**	56.1
Debt to invested capital excluding non recourse debt (%)		**53.5**	52.6
Return on shareholders' equity (%)		**9.1**	6.9
Comparable return on shareholders' equity[(1), (2)] (%)		**8.1**	6.9
Return on capital employed[(1)] (%)		**6.4**	5.7
Comparable return on capital employed[(1), (2)] (%)		**6.6**	5.8
Cash dividends per share[(1)] ($)		**1.16**	1.16
Price/earnings ratio[(1)] (times)		**20.1**	26.1
Earnings coverage[(1)] (times)		**1.9**	1.9
Dividend payout ratio based on net earnings[(1)] (%)		**107.7**	129.8
Dividend payout ratio based on comparable earnings[(1), (2)] (%)		**120.5**	129.8
Dividend coverage[(1)] (times)		**3.0**	2.5
Dividend yield[(1)] (%)		**5.3**	4.9
Cash flow to debt[(1)] (%)		**21.2**	20.1
Cash flow to interest coverage[(1)] (times)		**4.6**	4.9

(1) Last 12 months

(2) These ratios incorporate items that are not defined under Canadian GAAP. None of these measurements are used to enhance the Corporation's reported financial performance or position. 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-GAAP measure used in this calculation, refer to the Non-GAAP Measures section of this MD&A.

RATIO FORMULAS

Debt to invested capital = (debt – cash and cash equivalents) / (debt + non-controlling interests + shareholders' equity – cash and cash equivalents)

Return on shareholders' equity = net earnings or earnings on a comparable basis / average shareholders' equity 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/earnings ratio = current period's close price / basic earnings per share

Earnings coverage = (net earnings + income taxes + net interest expense) / (interest on debt – interest income)

Dividend payout ratio = dividends / net earnings or earnings on a comparable basis

Dividend coverage = cash flow from operating activities / common share dividends

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 + net interest expense) / (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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