TransAlta™

TRANSALTA CORPORATION

SECOND QUARTER REPORT FOR 2007

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 page 28 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 six months ended June 30, 2007 and 2006, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in our annual report for the year ended Dec. 31, 2006. 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 ("GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated July 27, 2007. 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 Corporate Development and Marketing ("CD&M"). Our segments are supported by a corporate group that provides finance, treasury, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, and other administrative support.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency 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 is reflected in the equity section of the consolidated balance sheets.

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

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Availability (%)	**83.6**	85.1	**85.9**	91.0
Production (GWh)	**11,497**	10,051	**24,194**	22,495
Revenue	**$ 665.5**	$ 599.0	**$ 1,375.4**	$ 1,332.7
Gross margin[1]	**$ 355.7**	$ 339.1	**$ 733.6**	$ 733.1
Operating income [1]	**$ 90.5**	$ 75.7	**$ 228.8**	$ 229.7
Net earnings	**$ 57.2**	$ 86.4	**$ 113.4**	$ 155.6
Basic and diluted earnings per common share	**$ 0.28**	$ 0.43	**$ 0.56**	$ 0.78
Cash flow from operating activities	**$ 227.6**	$ 66.8	**$ 558.4**	$ 267.1

1 *Gross margin and Operating income are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 26 of this MD&A for a further discussion of Gross margin and Operating income, including a reconciliation to net earnings.*

	June 30, 2007	Dec. 31, 2006
Total assets	**$ 7,156.5**	$ 7,460.1
Total long-term financial liabilities	**$ 3,203.5**	$ 3,094.1
Cash dividends declared per share	**$ 0.25**	$ 1.00

AVAILABILITY & PRODUCTION

Availability for the three months ended June 30, 2007 decreased compared to the same period in 2006 due to higher derates at the Centralia Coal-fired plant ("Centralia Coal") due to test burning Powder River Basin ("PRB") coal and higher unplanned outages at the Centralia Gas-fired plant ("Centralia Gas") offset by lower planned and unplanned outages at Sheerness and at various other gas facilities.

Availability for the six months ended June 30, 2007 decreased to 85.9 per cent from 91.0 per cent compared to the same period in 2006 primarily due to derating at Centralia Coal due to test burning PRB coal in the first and second quarters of 2007.

Production for the second quarter increased 1,446 gigawatt hours ("GWh") compared to the same period in 2006 as a result of increased production at Centralia Coal as in 2006 we reduced production in order to take advantage of market pricing. Production for the first six months of 2007 increased 1,699 GWh compared to the same period in 2006 primarily due to increased production at Centralia Coal.

NET EARNINGS

For the three and six months ended June 30, 2007, reported net earnings decreased to $57.2 million from $86.4 million and to $113.4 million from $155.6 million compared to the same periods in 2006. For the three months ended June 30, 2007, comparable earnings[1] were $41.9 million ($0.21 per common share) compared to $31.1 million ($0.16 per common share) in the same period in 2006. Comparable earnings for the six months ended June 30, 2007 were $98.1 million ($0.48 per common share), compared to $106.5 million ($0.53 per common share) over the same period in 2006.

A reconciliation of net earnings is presented below:

	3 months ended June 30	6 months ended June 30
Net earnings, 2006	$ 86.4	$ 155.6
Increase in Generation gross margins (before mark-to-market losses)	52.0	48.5
Increase in Generation mark-to-market losses	(26.2)	(40.0)
Decrease in CD&M margins	(9.2)	(8.0)
Decrease / (Increase) in operations, maintenance and administration costs	(4.0)	(6.1)
Decrease in depreciation expense	1.9	4.4
Gain on sale of Centralia mining equipment	11.7	11.7
Decrease in net interest expense	2.3	5.5
Increase in equity loss	(4.1)	(12.0)
(Increase) / Decrease in non-controlling interest	(1.8)	1.1
Increase in income tax expense	(57.7)	(53.9)
Other	5.9	6.6
Net earnings, 2007	**$ 57.2**	**$ 113.4**

Generation gross margins, before mark-to-market losses, increased by $52.0 million for the three months ended June 30, 2007 as a result of higher production at Centralia Coal and favorable pricing in Alberta and the Pacific Northwest markets, and lower coal costs at Centralia Coal partially offset by higher coal costs at the Alberta Thermal plants ("Alberta Thermal").

Generation gross margins, before mark-to-market losses, increased by $48.5 million for the six months ended June 30, 2007 as a result of favourable pricing in the Alberta market and at Centralia Coal combined with lower fuel costs and increased production at Centralia Coal, partially offset by higher unplanned outages, increased coal costs at Alberta Thermal, and lower margins at Ottawa.

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1 Comparable earnings is not defined under Canadian GAAP. 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 prior periods' results. Refer to the Non-GAAP Measures section on page 26 of this MD&A for further discussion of comparable earnings, including reconciliation to net earnings.

For the three and six months ended June 30, 2007, we recognized pre-tax mark-to-market losses of $26.2 million and $40.0 million, respectively, on certain contracts at Centralia Coal that no longer qualify for hedge accounting. These losses resulted from the reversal of gains recognized in the fourth quarter of 2006 on a portion of these contracts, new positions entered into for 2008, and from changes in forward prices which do not affect the final settlement amount received from these contracts. The fair value of future contracts will continue to fluctuate as market prices change.

CD&M gross margins decreased $9.2 million and $8.0 million for the three and six months ended June 30, 2007 compared to the same periods in 2006 due to lower margins on trading activities in the Western region.

Operations, maintenance, and administration ("OM&A") costs for the three and six months ended June 30, 2007 increased $4.0 million and $6.1 million, respectively, compared to the same period in 2006 as a result of increased investment in our information technology infrastructure and timing of other expenses.

Depreciation expense decreased $1.9 million for the three months ended June 30, 2007 compared to 2006 primarily due to more parts replaced during planned maintenance in 2006 and lower depreciation as a result of the impairment of Centralia gas recorded in 2006 partially offset by the impact the reclassification of the asset retirement obligation ("ARO") accretion expense at the Centralia Mine from cost of sales to depreciation and increased depreciation as a result of capital spending in 2006.

In addition to the above, for the six months ended June 30, 2007, depreciation expense decreased $4.4 million compared to the same period in 2006, due to the impairment recorded in 2006 on turbines held in inventory partially offset by increased capital spending in 2006.

During the second quarter we sold equipment previously used in our Centralia mining operations with a recorded value of $11.6 million, received proceeds of $23.3 million, and recorded a gain of $11.7 million.

For the three and six months ended June 30, 2007, net interest expense decreased $2.3 million and $5.5 million, respectively, mainly due to lower long-term debt levels and higher interest income on cash deposits partially offset by the gains recognized as a result of unwinding of net investment hedges and higher short-term debt balances. For the three and six months ended June 30, 2007, net debt of $96.2 million and $115.0 million, respectively, was repaid. Preferred securities of $175 million were repaid in the first quarter on 2007.

For the three and six months ended June 30, 2007, equity loss increased $4.1 million and $12.0 million respectively mainly due to lower margins and higher interest expense as a result of refinancing these subsidiaries.

For the three months ended June 30, 2007, non-controlling interests increased by $1.8 million due to higher earnings at TransAlta Cogeneration, L.P. ("TA Cogen") primarily as a result of higher margins at Sheerness partially offset by lower margins at Ottawa.

For the six months ended June 30, 2007, non-controlling interests decreased by $1.1 million due to lower earnings at TA Cogen as a result of lower margins at Ottawa partially offset by higher margins at Sheerness in the second quarter.

Income taxes increased compared to the same period in 2006, due to the one-time reduction in tax rates in the second quarter of 2006. The effective tax rates for the quarter and six months ended June 30, 2007 were 21.4 per cent and 24.1 per cent compared to 9.9 per cent and 19.8 per cent respectively for the same periods in 2006.

CASH FLOW

Cash flow from operating activities for the three months ended June 30, 2007 increased $160.8 million compared to the same period in 2006 mainly due to higher cash earnings and favourable cash flows from working capital due to timing of collections of accounts receivable and from to cash being consumed in 2006 as a result of building coal inventory at Centralia Coal.

Cash flow from operating activities for the six months ended June 30, 2007 increased $291.3 million compared to the same period in 2006 mainly due to cash being consumed to build coal inventory at Centralia Coal in 2006 and due to the timing of collections of revenues. During the first quarter of 2007, $185 million of contractually scheduled payments related to 2006 were collected. In the third quarter we will only receive two month's worth of revenue under our Power Purchase Agreements ("PPAs") due to contractual timing of scheduled payments. Further, in the fourth quarter a payment relating to 2007 PPA revenues will not be received until Jan. 2, 2008. While there is variability in the timing of cash collected, during 2007 we will receive twelve months of revenues earned under the PPAs.

The key factors responsible for these changes are listed below in the reconciliation of cash flow from operating activities for the three months ended June 30, 2006 to 2007:

	3 months ended June 30	6 months ended June 30
Cash flow from operating activities, 2006	$ 66.8	$ 267.1
Increased / (decreased) cash earnings	19.0	(0.3)
Collection of receivables related to 2006 revenue	-	185.0
Changes in non-cash working capital	141.8	106.6
Cash flow from operating activities, 2007	**$ 227.6**	**$ 558.4**

At June 30, 2007, our total debt (including non-recourse debt) to invested capital ratio[1] was 44.0 per cent (40.9 per cent excluding non-recourse debt and restricted cash). This is comparable to the Dec. 31, 2006 ratio of 44.0 per cent (40.5 per cent excluding non-recourse debt).

SIGNIFICANT EVENTS

Three months ended June 30, 2007

TransAlta Power, L.P.

On June 18, 2007, TransAlta Power, L.P. announced that it will record a non-cash charge to earnings in the second quarter and a corresponding reduction in the book value of its equity investment in TransAlta Cogeneration, L.P. ("TA Cogen") to reflect the tax effect of differences between the book and tax values of the assets of TA Cogen. This was as a result of tax legislation which was substantively enacted on June 12, 2007. There is no impact to TransAlta's earnings as the tax effect of these temporary differences have been accounted for in the accounts of TransAlta since its initial investment in TA Cogen.

On May 22, 2007, TransAlta Power L.P. announced the commencement of a strategic review. This process includes seeking proposals from potential buyers. TransAlta Corporation has indicated that it will consider its alternatives within the framework of the process but does not currently have any intention to acquire TransAlta Power nor sell its 50.01% interest in TA Cogen.

Dragline deposit

On June 21, 2007, TransAlta Utilities Corporation, a subsidiary of TransAlta Corporation, entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal for the Keephills 3 joint venture project. TransAlta's portion of the total dragline purchase costs are approximately $110 million, with final payments for goods and services due by May 2010. Total anticipated payments under this agreement in 2007 are $16 million.

[1] This ratio is further defined on page 51

Six months ended June 30, 2007

Power Purchase Agreement with New Brunswick Power

On Jan. 19, 2007, we announced a 25 year long-term contract with New Brunswick Power Distribution and Customer Service Corporation to provide 75 megawatts ("MW") of wind power. We will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills") with an estimated capital cost of $130 million. Commercial operations are expected to begin by the end of 2008.

Keephills 3 Power Plant

On Feb. 26, 2007, we announced that we will be building the 450 MW Keephills 3 coal-fired power plant. The plant will be developed jointly by EPCOR Utilities Inc. ("EPCOR") and TransAlta. The capital cost of the project is expected to be approximately $1.6 billion, including associated mine capital, and is anticipated to begin commercial operations in the first quarter of 2011. TransAlta will own a 50 percent interest in this unit.

2007 Canadian Federal Budget

The Canadian Federal Budget released on March 19, 2007 proposes to disallow the deductibility of interest on debt incurred to invest in foreign affiliates. We are currently evaluating the impact of this proposed legislation.

Greenhouse Gas Emissions Standards

On March 8, 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which outlines the proposed approach to greenhouse gas ("GHG") emissions, effective July 1, 2007. Under the proposed legislation, the baselines and targets for greenhouse gas emissions intensity are set on a facility by facility basis. While many regulatory details and guidance documents have yet to be developed, TransAlta anticipates being able to meet these requirements as currently proposed. On June 27, 2007, this legislation became substantially enacted and came into force July 1, 2007. The PPA's for our Alberta based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers. After flow through these compliance costs are estimated to be approximately $3 million in 2007 and $7 million per year thereafter.

On April 26, 2007, the Canadian government released details of its proposed environmental legislation. The federal plan calls for an 18 per cent reduction in GHG emission intensity starting in 2010, increasing to a 20 per cent absolute reduction requirement by 2020. Compliance can be achieved through direct emission reductions, payment into a technology fund at a fixed price, or through the purchase of offset credits. The proposed legislation also calls for a reduction in air pollutants such as sulphur dioxide, nitrous oxide, mercury, and particulates starting in the 2012 - 2015 period. Proposed reduction caps range from 45 per cent to 60 per cent. A number of material details in the federal plan are still to be determined, including its interaction with provincial programs, which will allow a reasonable determination of future compliance costs. The PPA's for our Alberta based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers.

Both the Saskatchewan and Ontario governments, on June 14 and 18, 2007 respectively, introduced GHG programs. However, neither government provided any details as to how the plans would affect power generation facilities other than Ontario's commitment to close coal units by 2014.

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect July 22, 2007. TransAlta's operations will not be impacted by the bill's performance standards at the current time, provided the facilities do not change ownership or enter into power sales contracts longer than five years.

SUBSEQUENT EVENT

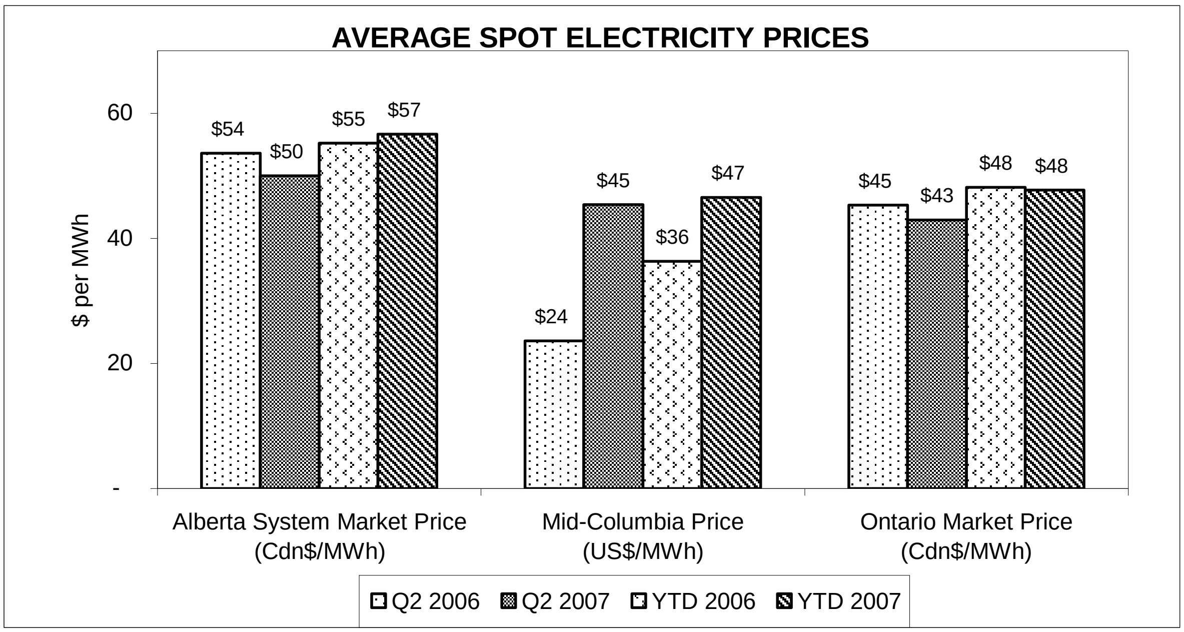
Power purchase agreement

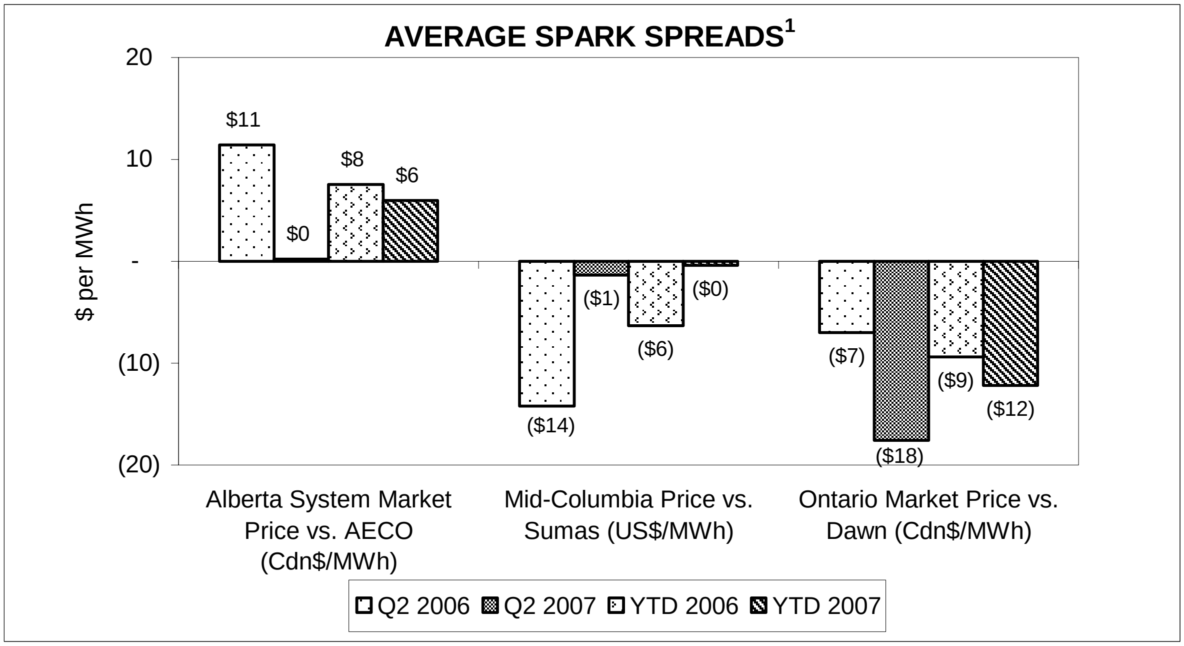
On July 17, 2007, we amended our power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation to increase capacity under the agreement from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills wind power project will also increase by $40 million to $170 million. We also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site. Under the purchase and sale agreement, TransAlta will acquire Canadian Hydro's Fairfield Hill wind power site, including the option to develop the site at a future date.

MARKET PRICES AND SPARK SPREADS

The change in prices of electricity, natural gas, and resulting spark spreads in our three major markets – Alberta, Ontario, and the Pacific Northwest Region of the United States, affect our Generation and Energy Trading businesses.

Approximately 12 per cent of the estimated production in 2007 for our gas fired facilities and three per cent of the estimated 2007 production for our coal-fired facilities have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes 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.





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

For the second quarter, Alberta and Ontario power prices were comparable as Alberta had relatively normal weather and lower forced outage rates which moderated prices, and Ontario continued to have weaker demand and healthy supply, which depressed prices, while the Pacific Northwest spot prices increased dramatically due to much less hydro flows along the Columbia River system. Spark spreads increased in the Pacific Northwest but decreased in Alberta and Ontario for the three months ended June 30, 2007 compared to the same period in 2006. Spark spreads remained negative for the past two years in Ontario and the Pacific Northwest for the second quarter. The effect of these prices upon the margins from our generating facilities and our trading activities are described in further detail below.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: *Owns and operates hydro, wind, geothermal, gas- and coal-fired plants 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 (see the detailed discussion of the four revenue streams in our annual report for the year ended Dec. 31, 2006). At June 30, 2007, Generation had 8,371 MW of gross generating capacity[1] in operation (7,964 MW net ownership interest) and 374 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, please refer to the MD&A contained in our 2006 annual report.*

During the second quarter we increased the measured gross generating capacity of Sheerness by 5 MW (2.5 MW net of ownership interest).

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1 TransAlta measures 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.

The results of the Generation segment are as follows:

3 months ended June 30	2007 Total	2007 Per installed MWh	2006 Total	2006 Per installed MWh
Revenues	$ 595.1	$ 32.46	$ 554.6	$ 30.27
Fuel and purchased power	(255.9)	(13.96)	(241.2)	(13.16)
Gross margin	339.2	18.50	313.4	17.11
Operations, maintenance and administration	128.7	7.02	128.8	7.03
Depreciation and amortization	96.9	5.29	98.8	5.39
Taxes, other than income taxes	5.3	0.29	5.6	0.31
Intersegment cost allocation	6.6	0.36	7.0	0.38
Operating expenses	237.5	12.96	240.2	13.11
Operating income	$ 101.7	$ 5.55	$ 73.2	$ 4.00
Installed capacity (GWh)	18,332		18,322	
Production (GWh)	11,497		10,051	
Availability (%)	83.6		85.1	

6 months ended June 30	2007 Total	2007 Per installed MWh	2006 Total	2006 Per installed MWh
Revenues	$ 1,253.2	$ 34.19	$ 1,234.6	33.69
Fuel and purchased power	(546.6)	(14.91)	(536.5)	(14.64)
Gross margin	706.6	19.28	698.1	19.05
Operations, maintenance and administration	232.7	6.35	233.2	6.36
Depreciation and amortization	192.3	5.25	196.9	5.37
Taxes, other than income taxes	10.7	0.29	11.1	0.30
Intersegment cost allocation	13.7	0.37	13.9	0.38
Operating expenses	449.4	12.26	455.1	12.41
Operating income	$ 257.2	$ 7.02	$ 243.0	$ 6.64
Installed capacity (GWh)	36,654		36,643	
Production (GWh)	24,194		22,495	
Availability (%)	85.9		91.0	

Availability

Availability for the three months ended June 30, 2007 decreased compared to the same period in 2006 due to higher derates at Centralia Coal due to test burning PRB coal and higher unplanned outages at Centralia Gas offset by lower planned and unplanned outages at Sheerness and at various other gas facilities.

Availability for the six months ended June 30, 2007 decreased to 85.9 per cent from 91.0 per cent compared to the same period in 2006 primarily due to derating at Centralia Coal due to test burning PRB coal in the first and second quarters of 2007. The underlying availability after adjusting for Centralia Coal derates is 87.3 per cent and 90.2 per cent for the three and six months ended June 30, 2007, respectively.

Production

Production for the second quarter increased by 1,446 GWh compared to the same period in 2006 as a result of the economic dispatch at Centralia Coal in 2006 (1,466 GWh), lower planned outages at Alberta Thermal (120 GWh), lower planned and unplanned outages at Sheerness (85 GWh), and increased hydro production (88 GWh) partially offset by higher unplanned outages at Alberta Thermal (115 GWh), lower PPA customer demand (131 GWh), and lower production at Poplar Creek (84 GWh).

Production for the six months ended June 30, 2007 increased by 1,699 GWh compared to the same period in 2006 due to the economic dispatch at Centralia Coal in the second quarter of 2006 (1,466 GWh), increased hydro production (41 GWh), increased customer demand at

Fort Saskatchewan (159 GWh), favorable market conditions at Sarnia (149 GWh), lower planned and unplanned outages at Sheerness (77 GWh), and increased production at Ottawa as we curtailed production in the first quarter of 2006 to sell gas (81 GWh) partially offset by higher unplanned outages at Alberta Thermal (262 GWh) and lower PPA customer demand (80 GWh).

Revenue

Revenue increased by $40.5 million for the three months ended June 30, 2007 as compared to the same period in 2006 primarily due to higher pricing and production at Centralia Coal ($35.6 million), lower planned outages at Alberta Thermal ($4.7 million), increased hydro production ($2.7 million), lower planned and unplanned outages at Sheerness ($6.0 million), favorable commercial settlements ($12.0 million), favorable pricing at CE Gen ($4.6 million) and Alberta Thermal ($6.1 million), and higher revenues at our Australian operations ($4.0 million) partially offset by higher unplanned outages at Alberta Thermal ($5.9 million), mark-to-market losses at Centralia Coal ($26.2 million), and from lower revenue from Ottawa gas sales ($9.2 million).

For the six months ended June 30, 2007 revenue increased $18.6 million due to higher pricing and production at Centralia Coal ($33.6 million) and CE Gen ($7.8 million), higher production and sparkspreads at Poplar Creek in the first quarter ($6.4 million), favorable commercial settlements ($12.0 million), lower planned and unplanned outages at Sheerness ($5.0 million), higher production and increased fuel costs that are recovered from customers at Sarnia ($11.7 million), higher revenues at our Australian operations ($7.8 million), and favourable pricing at Alberta Thermal ($8.7 million) partially offset by the sale of emission credits at Centralia Coal in the first quarter of 2006 ($7.2 million), mark-to-market losses at Centralia Coal ($40.0 million), lower revenue from gas sales at Ottawa ($15.7 million), and higher unplanned outages at Alberta Thermal ($14.5 million) .

Fuel and purchased power

Fuel and purchased power increased by $14.7 million for the three months ended June 30, 2007 compared to the same period in 2006 due to higher coal costs at Alberta Thermal ($9.6 million), increased production at Centralia Coal ($17.2 million), increased production and gas prices at Sarnia ($8.4 million), increased fuel costs at CE Gen ($4.9 million), and higher replacement power prices at Centralia Coal ($8.4 million) partially offset by incremental gas purchases at Ottawa in 2006 ($5.6 million), lower coal costs at Centralia Coal ($25.4 million), and lower production at Alberta Thermal ($2.4 million).

For the six months ended June 30, 2007 fuel and purchased power increased **$**10.1 million due to higher coal costs at Alberta Thermal ($19.3 million), increased fuel costs and production at CE Gen ($7.1 million) and Sarnia ($14.0 million), increased production at Centralia Coal ($10.0 million), and higher replacement power prices in the second quarter at Centralia Coal ($8.4 million) partially offset by incremental gas purchases at Ottawa in 2006 ($5.6 million), lower fuel costs at Centralia Coal ($32.1 million), and lower production at Alberta Thermal ($5.5 million).

Operations, maintenance and administration expense

For the three and six months ended June 30, 2007, OM&A expense decreased primarily due to the timing of maintenance spending at Centralia Coal partially offset by the economic dispatch in Centralia in the second quarter of 2006.

Depreciation expense

Depreciation expense decreased $1.9 million for the three months ended June 30, 2007 compared to 2006 primarily due to more parts replaced during planned maintenance in 2006 ($2.9 million) and lower depreciation as a result of the impairment of Centralia gas recorded in 2006 ($1.2 million) partially offset by increased depreciation as a result of capital spending in 2006 ($1.4 million) and by the impact of the reclassification of the asset retirement obligation (“ARO”) accretion expense at the Centralia Mine from cost of sales to depreciation ($4.4 million).

For active mines, accretion expense related to ARO is included in cost of sales. However, the Centralia mine is currently considered to be inactive and therefore, accretion expense is now classified as part of depreciation expense. The adjustment of $4.4 million recorded in the second quarter reflects the reclassification of six months of accretion expense. In 2006, $2.1 million and $4.3 million of accretion expense related to the Centralia mine was recorded in cost of sales, respectively, for the three and six months ended June 30, 2006.

For the six months ended June 30, 2007, depreciation expense decreased $4.6 million compared to the same period in 2006, due to the impairment recorded in 2006 on turbines held in inventory ($9.2 million), lower depreciation at Centralia Gas ($2.4 million), and more parts replaced during planned maintenance in 2006 ($1.7 million) partially offset by the reclassification of ARO accretion at the Centralia Mine ($4.4 million) and increased depreciation as a result of capital spending in 2006 ($3.1 million).

Planned maintenance

The table below shows the amount of planned maintenance capitalized and expensed in the three and six months ended June 30, 2007 and 2006, excluding CE Gen and Mexico:

	Coal		Gas and Hydro		Total	
3 months ended June 30	**2007**	2006	**2007**	2006	**2007**	2006
Capitalized	**$ 26.3**	$ 27.8	**$ 9.0**	$ 9.8	**$ 35.3**	$ 37.6
Expensed	**23.9**	27.9	**0.7**	0.9	**24.6**	28.8
	$ 50.2	$ 55.7	**$ 9.7**	$ 10.7	**$ 59.9**	$ 66.4
GWh lost	**1,137**	1,379	**69**	93	**1,206**	1,472

	Coal		Gas and Hydro		Total	
6 months ended June 30	**2007**	2006	**2007**	2006	**2007**	2006
Capitalized	**$ 29.1**	$ 32.7	**$ 9.3**	$ 12.4	**$ 38.4**	$ 45.1
Expensed	**28.5**	30.2	**0.7**	1.3	**29.2**	31.5
	$ 57.6	$ 62.9	**$ 10.0**	$ 13.7	**$ 67.6**	$ 76.6
GWh lost	**1,248**	1,383	**72**	105	**1,320**	1,488

For the three months ended June 30, 2007, production lost due to planned maintenance decreased by 266 GWh compared to the same period in 2006 mainly due to lower planned outages at Alberta Thermal (120 GWh), Sheerness (41 GWh), Centralia Coal (80 GWh), and Meridian (30 GWh).

For the six months ended June 30, 2007, production lost due to planned maintenance decreased by 168 GWh due to lower planned outages at Alberta Thermal (13 GWh), Sheerness (41 GWh), Meridian (30 GWh), and Centralia Coal (80 GWh).

For the three and six months ended June 30, 2007 total capitalized and expensed maintenance costs decreased compared to the same periods in 2006 mainly due to lower planned maintenance activities at Centralia.

Generation gross margins

Generation's production volumes, electricity and steam production revenues and fuel and purchased power costs are presented below, based on geographical regions. The change in presentation of gross margins to a regional breakdown allows for more representative information of Generation's production volumes, electricity and steam production revenues and fuel and purchased power costs which are presented below:

3 months ended June 30, 2007	**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**
Western Canada	**8,012**	**11,320**	**$ 305.5**	**$ 98.8**	**$ 206.7**	**$ 26.99**	**$ 8.73**	**$ 18.26**
Eastern Canada	**824**	**1,793**	**105.7**	**74.5**	**$ 31.2**	**58.95**	**41.55**	**17.40**
International	**2,661**	**5,219**	**183.9**	**82.6**	**$ 101.3**	**35.24**	**15.83**	**19.40**
	11,497	**18,332**	**$ 595.1**	**$ 255.9**	**$ 339.2**	**$ 32.46**	**$ 13.96**	**$ 18.50**

3 months ended June 30, 2006	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
Western Canada	7,988	11,310	$ 277.8	$ 85.2	$ 192.6	$ 24.56	$ 7.53	$ 17.03
Eastern Canada	802	1,793	109.4	70.9	$ 38.5	61.02	39.55	21.47
International	1,261	5,219	167.4	85.1	$ 82.3	32.08	16.31	15.77
	10,051	18,322	$ 554.6	$ 241.2	$ 313.4	$ 30.27	$ 13.16	$ 17.11

6 months ended June 30, 2007	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
Western Canada	**16,829**	**22,629**	**$ 653.9**	**$ 216.4**	**$ 437.5**	**$ 28.90**	**$ 9.56**	**$ 19.34**
Eastern Canada	**1,809**	**3,587**	**233.7**	**159.9**	**$ 73.8**	**65.16**	**44.58**	**20.58**
International	**5,556**	**10,438**	**365.6**	**170.3**	**$ 195.3**	**35.03**	**16.32**	**18.71**
	24,194	**36,654**	**$ 1,253.2**	**$ 546.6**	**$ 706.6**	**$ 34.19**	**$ 14.91**	**$ 19.28**

6 months ended June 30, 2006	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
Western Canada	16,791	22,618	$ 625.0	$ 194.3	$ 430.7	$ 27.63	$ 8.59	$ 19.04
Eastern Canada	1,573	3,587	240.0	153.5	86.5	66.90	42.79	24.11
International	4,131	10,438	369.6	188.7	180.9	35.41	18.08	17.33
	22,495	36,643	$ 1,234.6	$ 536.5	$ 698.1	$ 33.69	$ 14.64	$ 19.05

Western Canada

Our Western Canada assets consist of five coal units, three gas-fired facilities, thirteen hydro facilities, and three wind farms with a total gross generating capacity of 5,169 MW (4,884 MW net of ownership interest). We are currently constructing a 450 MW coal-fired unit at our Keephills facility under a joint venture with EPCOR and are adding an additional 53 MW of capacity to unit four at our Sundance facility. The additional capacity for the Sundance facility is scheduled to enter production in the fourth quarter of 2007, while the additional unit at our Keephills facility is scheduled to enter commercial production in 2011.

Our Sundance, Keephills, and Sheerness plants and hydro facilities operate under PPAs with a gross generating capacity of 3,977 MW (3,782 MW net of ownership interest). Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability and an excess energy payment for power production above committed capacity. Additional capacity added to these units which are not included in capacity covered by the PPAs are sold on the merchant market.

Our Wabamun, Genesee 3, Summerview, and a portion of our Poplar Creek facilities sell their production on the merchant spot market. In order to manage our exposure to changes in spot electricity prices as well as capture value, we use financial hedges to guarantee prices for production.

Due to their close physical proximity, three of our coal units, Sundance, Keephills, and Wabamun, are operated and managed collectively and are referred to as “Alberta Thermal.”

Our Castle River, McBride Lake, Meridian, Fort Saskatchewan, and a significant portion of our Poplar Creek assets earn revenues under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam as well as for ancillary services. These contracts are for an original term of at least ten years and payments do not fluctuate significantly with changes in levels of production.

Production for the three months ended June 30, 2007 increased 24 GWh compared to the same period in 2006 due to higher hydro production (88 GWh), lower planned and unplanned outages at Sheerness (85 GWh), lower planned outages at Alberta Thermal (120 GWh), and increased customer demand at Fort Saskatchewan (39 GWh) partially offset by lower PPA demand (131 GWh), lower production at Poplar Creek (84 GWh), and higher unplanned outages at AB Thermal (115 GWh).

For the six months ended June 30, 2007, production increased 38 GWh due to increased customer demand at Fort Saskatchewan (159 GWh), lower planned and unplanned outages at Sheerness (77 GWh), increased hydro production (41 GWh), higher excess energy sales (50 GWh), and lower planned and unplanned outages at Meridian (42 GWh) partially offset by lower PPA demand (80 GWh), and higher unplanned outages at Alberta Thermal (262 GWh).

Gross margin for the three months ended June 30, 2007 increased $14.1 million ($1.23 per installed MWh), due to increased hydro volumes ($2.6 million), lower planned outages at Alberta Thermal ($5.8 million), lower planned and unplanned outages at Sheerness ($5.3 million), favorable pricing at Alberta coal plants ($4.3 million), and favorable commercial settlements ($12.0 million) partially offset by higher coal costs at Alberta Thermal ($9.6 million) and increased unplanned outages at Alberta Thermal ($4.7 million).

Gross margin for the six months ended June 30, 2007 increased $6.8 million ($0.30 per installed MWh) due to higher hydro production ($3.5 million), lower planned and unplanned outages at Sheerness in the second quarter ($5.3 million), higher prices ($10.8 million), favorable production at Meridian ($2.2 million), higher excess energy sales at our PPA plants ($2.2 million), and favorable commercial settlements ($12.0 million) partially offset by higher coal costs ($19.3 million) and higher unplanned outages at Alberta Thermal ($12.1 million).

Eastern Canada

Our Eastern Canada assets consist of four gas fired facilities with a total gross generating capacity of 819 MW (697 MW net of ownership interest). All four facilities earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Kent Hills, a 96 MW wind farm located in New Brunswick, is currently under development and is scheduled to begin commercial operations in 2008.

Production for the three months ended June 30, 2007 increased 22 GWh mainly as a result of favourable market conditions at Sarnia.

Production for the six months ended June 30, 2007 increased 236 GWh due to higher production at Sarnia primarily resulting from favorable market conditions (149 GWh) and increased production at Ottawa due to gas sales in the first quarter of 2006 (81 GWh).

For the three and six months ended June 30, 2007, gross margins decreased $7.3 million ($4.07 per installed MWh) and $12.7 million ($3.55 per installed MWh) respectively mainly as a result of lower gas sales at Ottawa ($3.6 million and $10.1 million respectively).

International

Our International assets consist of gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,083 MW and gas and diesel fired assets in Australia with a generating capacity of 300 MW. 378 MW of our United States assets are operated by CE Gen, a joint venture owned 50 per cent by TransAlta.

Our Centralia Coal, Centralia Gas, Binghamton, Power Resources, Skookumchuck, and one unit of our Imperial Valley assets are merchant facilities. To reduce the volatility and risk in merchant markets, we use a variety of physical and financial hedges to secure prices received for electrical production. The remainder of our international facilities operate under long-term contracts.

For the three and six months ended June 30, 2007, production increased 1,400 GWh and 1,425 GWh, respectively, mainly as a result of higher production at Centralia in the second quarter (1,466 GWh).

For the three months ended June 30, 2007, gross margins increased $19.0 million ($3.63 per installed MWh) compared to the same period in 2006 due to increased production at Centralia Coal ($4.8 million), favorable exchange rates and margins at Australia ($3.5 million), favorable pricing ($11.8 million) and lower coal costs at Centralia Coal ($25.4 million), partially offset by mark-to-market losses relating to gains previously recorded in 2006 on contracts that no longer qualify for hedge accounting and on price changes on future contracts that do not qualify for hedge accounting ($26.2 million) and higher replacement power prices ($8.4 million).

For the six months ended June 30, 2007 gross margins increased $14.4 million ($1.38 per installed MWh) due to favourable pricing at Centralia Coal ($18.3 million), favourable exchange rates and margins at Australia ($4.5 million), increased production at Centralia Coal in the second quarter ($4.8 million) and lower coal costs at Centralia ($32.1 million) partially offset by the sale of emission credits at Centralia Coal in 2006 ($7.2 million), higher replacement power prices ($8.4 million), and mark-to-market losses on certain contracts at Centralia Coal ($40.0 million).

CORPORATE DEVELOPMENT AND MARKETING: *derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta owned generation assets. CD&M also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas, coal and transmission capacity to effectively manage available generating capacity as well as fuel and transmission needs on behalf of Generation. These results are included in the Generation segment. Key performance indicators for CD&M's proprietary trading include margins and value at risk.*

Our Energy Trading activities utilize a variety of instruments to manage risk, earn trading revenue and gain market information. Our trading strategies consist of shorter-term physical and financial trades in regions where we have assets and the markets that interconnect with those regions. The portfolio primarily consists of physical and financial derivative instruments including forwards, swaps, futures, and options in various commodities. These contracts meet the definition of trading activities and have been accounted for using fair values under Canadian GAAP. Changes in the fair values of the portfolio are recognized in income in the period they occur.

While trading products are generally consistent between periods, positions held and resulting earnings impacts will vary due to current and forecasted external market conditions. Positions for each region are established based on the market conditions and the risk reward ratio established for each trade at the time they are transacted. Results, therefore, will vary regionally or by strategy from one reported period to the next.

OM&A costs incurred within CD&M are allocated to the Generation segment based on an estimate of operating expenses and an estimated percentage of resources dedicated to providing the support and analysis. This fixed fee inter-segment allocation is represented as a cost recovery in CD&M and an operating expense within Generation.

The results of the CD&M segment are as follows:

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Revenues	**$ 70.4**	$ 44.4	**$ 122.2**	$ 98.1
Trading purchases	**(53.9)**	(18.7)	**(95.2)**	(63.1)
Gross margin	**16.5**	25.7	**27.0**	35.0
Operations, maintenance and administration	**8.3**	8.3	**16.9**	16.4
Depreciation and amortization	**0.3**	0.4	**0.7**	0.7
Intersegment cost allocation	**(6.6)**	(7.0)	**(13.7)**	(13.9)
Operating expenses	**2.0**	1.7	**3.9**	3.2
Operating income	**$ 14.5**	$ 24.0	**$ 23.1**	$ 31.8

For the three months ended June 30, 2007, gross margin decreased $9.2 million relative to the same period in 2006, due to exceptionally strong Western region trading results in 2006. In 2007, both Eastern and Western regions trading results evenly contributed to 2007 gross margin.

The decrease in gross margin for the six months ended June 30, 2007 compared to the same period 2006 is due to exceptionally strong Western region results in 2006 and from decreased gas trading margins in 2007 as a result of natural gas market volatility.

OM&A costs for the three months ended June 30, 2007 are consistent with the same period in 2006. For the six months ended June 30, 2007, OM&A costs increased $0.5 million due to increased staff compensation in the first quarter of 2007.

The inter-segment cost allocations are consistent with the prior comparable periods.

NET INTEREST EXPENSE

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Interest on long-term debt	**$ 36.8**	$ 34.7	**$ 75.6**	$ 68.8
Interest on short-term debt	**6.0**	2.5	**12.5**	6.2
Interest on preferred securities	**-**	3.4	**-**	6.8
Interest income	**(6.6)**	(2.6)	**(14.3)**	(3.3)
Capitalized interest	**(0.5)**	-	**(0.8)**	-
Net interest expense	**$ 35.7**	$ 38.0	**$ 73.0**	$ 78.5

For the three months ended June 30, 2007, net interest expense was $2.3 million lower than the comparable period in 2006 due to lower long-term debt levels and the strengthening of the Canadian dollar relative to the US dollar ($3.2 million), redemption of preferred securities in 2007 ($3.4 million), and higher interest income from cash deposits ($4.0 million) partially offset by higher short-term debt balances ($3.5 million) and the gain on the settlement of a net investment hedge in 2006 which is recorded as part of interest on long-term debt ($4.1 million).

For the six months ended June 30, 2007, net interest expense was $5.5 million lower than the comparable period in 2006 due to redemption of preferred securities in 2007 ($6.8 million), higher interest on cash deposits ($11.0 million), and the strengthening of the Canadian dollar relative to the US dollar and lower long-term debt balances ($7.0 million) partially offset by higher short-term debt balances ($6.3 million) and the interest gain on the unwind of a net investment hedge in 2006 which was recorded as part of interest expense on long-term debt ($10.2 million).

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests in the three months ended June 30, 2007 increased $1.8 million compared to the same period in 2006 due to higher margins at Sheerness due to lower planned and unplanned outages partially offset by lower margins at Ottawa.

For the six months ended June 30, 2007, earnings attributable to non-controlling interests decreased $1.1 million due to lower margins at Ottawa partially offset by higher margins at Sheerness in the second quarter of 2007.

EQUITY INCOME

As required under Accounting Guideline 15, *Variable Interest Accounting*, of the Canadian Institute of Chartered Accountants ("CICA"), our Mexican operations are accounted for as equity subsidiaries. However, these plants are owned by TransAlta and managed as part of the Generation segment. The table below summarizes key information from these operations.

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Availability (%)	**94.8**	85.0	**95.8**	88.1
Production (GWh)	**861**	876	**1,440**	1,488
Equity (loss) income	**$ (2.1)**	$ 2.0	**$ (11.0)**	1.0
Capital expenditures	**0.3**	2.0	**1.0**	8.0
Operating cash flow	**(4.4)**	10.3	**13.5**	17.5
Interest expense	**5.9**	3.0	**$ 15.9**	$ 12.9

For the three and six months ended June 30, 2007 availability increased due to lower planned maintenance at Chihuahua.

For the three months ended June 30, 2007 production decreased slightly due to lower customer demand at Campeche. For the six months ended June 30, 2007 production decreased due to lower customer demand at Campeche partially offset by lower planned outages at Chihuahua.

For the three months ended June 30, 2007, equity loss increased $4.1 million due to lower margins ($1.5 million), increased depreciation as a result of capital spending on planned maintenance in 2006 ($1.7 million), and increased costs as a result of refinancing these subsidiaries in 2006 ($3.0 million) partially offset by a loss incurred on unwinding a cross-currency swap in 2006 ($1.6 million).

For the six months ended June 30, 2007, equity loss increased $12.0 million due to lower margins ($3.4 million), increased depreciation as a result of capital spending on planned maintenance in 2006 ($3.3 million), timing of routine maintenance and other operating expenses ($2.6 million), and increased interest costs as a result of refinancing these subsidiaries in 2006 ($11.8 million) partially offset by the recognition of deferred financing fees in 2006 ($7.2 million) and a loss incurred on unwinding a cross-currency swap in 2006 ($1.6 million).

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INCOME TAXES

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Earnings before income taxes	**$ 63.0**	$ 34.5	**$ 139.2**	$ 127.5
Turbine impairment	**-**	-	**-**	9.6
Earnings before income taxes and turbine impairment	**$ 63.0**	$ 34.5	**$ 139.2**	$ 137.1
Income tax prior to adjustment for rate change	**13.5**	3.4	**33.5**	27.2
Change in tax rate related to prior periods	**(7.7)**	(55.3)	**(7.7)**	(55.3)
Income tax expense (recovery) per financial statements	**5.8**	(51.9)	**$ 25.8**	$ (28.1)
Net income	**$ 57.2**	**$ 86.4**	**$ 113.4**	**$ 155.6**
Effective tax rate (%)	**21.4**	**9.9**	**24.1**	**19.8**

As a result of the Tax Fairness Plan, Canadian corporate tax rates were reduced by 0.5 per cent beginning in 2011, resulting in a reduction of tax expense in the second quarter of $7.7 million which reflected the impact of these changes on prior year's earnings.

In 2006, as a result of Alberta and Federal budgets, comparable tax rates were reduced resulting in reduction of tax expense of $55.3 million which reflected the impact of these changes on prior year earnings.

Tax expense, excluding the impact of change in tax rate related to prior periods, increased in the three and six months ended June 30, 2007 from the same period in 2006 due to an increase in pre-tax income earnings and the effect of the change in mix of jurisdictions in which pre-tax income is earned.

FINANCIAL POSITION

The following chart outlines significant changes in the consolidated balance sheet from Dec. 31, 2006 to June 30, 2007:

	Increase/ (Decrease)	Explanation
Cash and cash equivalents	$ (12.5)	Refer to Consolidated Statements of Cash Flows
Accounts receivable	(230.1)	Timing of collections of November 2006 revenues and timing of collections of CD&M revenues
Prepaid expenses	14.0	Timing of insurance premiums and other prepaids
Inventory	(11.2)	Lower inventory balances at Centralia Coal
Restricted cash	(63.6)	Decrease in exchange rates and return of funds
Risk management assets (current and long-term)	52.6	Adopting new accounting standards on financial instruments and from price movements
Property, plant and equipment, net	(39.5)	Strengthening of the Canadian dollar compared to the U.S. dollar and depreciation expense partially offset by capital additions
Assets held for sale, net	(65.0)	Assets retained for use in reclamation activities and for use in operations at the Highvale mine combined with sale of other assets
Intangible assets	(44.2)	Amortization expense and the strengthening of the Canadian dollar
Short-term debt	(31.7)	Net decrease in short-term debt
Accounts payable and accrued liabilities	(71.4)	Timing of major maintenance activities, reclamation costs, and incentive payments partially offset by CD&M payments
Income taxes payable	(15.8)	Paid installments offset by current tax provision
Recourse long-term debt (including current portion)	(67.4)	Scheduled debt payments and decrease in exchange rates
Non-recourse long-term debt (including current portion)	(46.6)	Scheduled debt repayments
Risk management liabilities (current and long-term)	519.8	Result of adopting new accounting standards on financial instruments and from price movements
Deferred credits and other long-term liabilities (including current portion)	(42.6)	Normal accretion expense less liabilities settled and payment of Centralia mine closure costs
Net future income tax liabilities (including current portions)	(127.4)	Tax effect of adjustments related to new accounting standards on financial instruments
Non-controlling interests	(18.6)	Distributions in excess of earnings
Preferred securities (including current portions)	(175.0)	Preferred securities redeemed in 2007
Shareholders' equity	(322.0)	Adoption of new accounting standards and dividends declared partially offset by net earnings and shares issued

FINANCIAL INSTRUMENTS

On Jan. 1, 2007, we adopted four new accounting standards that were issued by the CICA: Section 1530, *Comprehensive Income*; Section 3855, *Financial Instruments – Recognition and Measurement*; Section 3861, *Financial Instruments – Disclosure and Presentation*; and Section 3865, *Hedges*. We adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income ("AOCI").

Section 1530 introduces comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). OCI represents changes in shareholders' equity during a period arising from transactions and other events with non-owner sources and includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, net of hedging activities, and changes in the fair value of the effective portion of cash flow hedging instruments.

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the consolidated balance sheet when we become a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value upon initial recognition except for certain related party transactions.

To present comparable 2006 balance sheet figures, prior year balances for foreign currency and interest rate financial instruments were reclassified. Short-term and long-term risk management assets were increased by $11.2 million and $43.2 million respectively, and current and long-term portions of other assets were reduced by the corresponding amounts. Short-term and long-term risk management liabilities were increased by $2.1 million and $13.0 million respectively, and current and long-term portions of deferred credits and other long-term liabilities were decreased by the corresponding amounts. As required under Section 1530, cumulative translation loss of $64.5 million was reclassified as the opening balance of AOCI.

The majority of the changes were reflected in the carrying value of cash flow hedges included in CD&M risk management assets and liabilities as well as in financial instruments used as hedges of debt and net investment of self-sustaining foreign subsidiaries. The impact of adopting these standards to our Dec. 31, 2006 balance sheet is outlined below:

	Price Risk Assets		Price Risk Liabilities		
	Current	**Long-Term**	**Current**	**Long-Term**	**Net**
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of CD&M net risk management assets (liabilities) outstanding at Dec. 31, 2006	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

The gross and net of tax impact of adopting these standards to the opening balance of AOCI are outlined below:

Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ 90.9
Fair value of CD&M net risk management liabilities outstanding at Dec. 31, 2006	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	47.7
Total fair value of risk liabilities	(173.5)
Change in fair value	(264.4)
Tax	(87.1)
Adjustment to opening Accumulated Other Comprehensive loss from fair values	$ (177.3)
Cumulative Translation Adjustment	(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$ (241.8)

The impact of these new accounting standards upon our risk management assets and liabilities is described in more detail below along with the changes in the values of these assets and liabilities in the current period.

RISK MANAGEMENT ASSETS AND LIABILITIES

Our risk management assets and liabilities are comprised of two major types: (1) those that are used in the CD&M and Generation segments in relation to energy trading activities, hedging activities, and other contracting activities and (2) those used in the hedging non-energy marketing transactions, debt, and the net investment in self-sustaining foreign subsidiaries. The changes in each of these are described below.

Energy Trading

Our energy trading risk management assets and liabilities represent the value of unsettled (unrealized) CD&M transactions and certain Generation contracting activities that are accounted for on a fair value basis. Contracts qualifying for hedge accounting are identified as “Hedges”. All other contracts are identified as “Non-Hedges”. With the exception of physical transmission contracts and gas storage assets, the fair value of all energy trading activities is based on quoted market prices or model valuations. All contracts are accounted for in accordance with EITF 02-3.

The following table shows the balance sheet classifications for energy trading risk management assets and liabilities separately by source of valuation:

Balance Sheet - Energy Trading	June 30, 2007			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to energy trading
Risk management assets				
- Current	**$ 6.5**	**$ 37.3**	**$ 43.8**	$ 61.0
- Long-term	**(2.9)**	**2.8**	**(0.1)**	21.9
Risk management liabilities				
- Current	**(116.4)**	**(30.6)**	**(147.0)**	(30.3)
- Long-term	**(376.2)**	**(1.2)**	**(377.4)**	(1.0)
Net risk management assets (liabilities) outstanding	**$ (489.0)**	**$ 8.3**	**$ (480.7)**	$ 51.6

As a result of adopting new accounting standards on financial instruments, as described on page 16, risk management assets and liabilities receiving hedge accounting are recorded at fair value. The impact upon previously reported values is shown in the table below along with the changes in those values during the first six months of 2007:

	Hedges		**Non-Hedges**		
Change in fair value of net assets (liabilities)	**Mark to Market**	**Mark to Model**	**Mark to Market**	**Mark to Model**	**Total**
Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	**$ 51.6**
Net risk management assets outstanding at Dec. 31, 2006 - *fair value*[1]	(253.0)	(19.8)	52.7	(1.1)	**(221.2)**
Contracts realized, amortized or settled during the period	(1.5)	1.8	(27.7)	(1.0)	**(28.4)**
Changes in values attributable to market price and other market changes	(180.3)	(11.2)	(5.7)	(2.5)	**(199.7)**
New contracts entered into during the current period	(42.3)	-	7.2	3.7	**(31.4)**
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	-	(17.3)	-	**-**
Net risk management assets (liabilities) outstanding at June 30, 2007	**$ (459.8)**	**$ (29.2)**	**$ 9.2**	**$ (0.9)**	**$ (480.7)**

[1] *As a result of adopting new accounting standards*

For the six months ended June 30, 2007, the fair value of our net risk management assets and liabilities associated with hedge positions decreased $216.2 million compared to Dec. 31, 2006 primarily due to value changes associated with contracts in existence at both Dec. 31, 2006 and June 30, 2007, and the change in value of new contracts entered into in 2007. Changes in net risk management assets and liabilities for hedge positions are reflected within the gross margin of the Generation business segment to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until the delivery date of the underlying product and contract settlement occurs.

For the six months ended June 30, 2007, the fair value of our net risk management assets and liabilities associated with non-hedge positions decreased $43.3 million compared to Dec. 31, 2006 due to contracts settled during the quarter and value changes associated with contracts in existence at both Dec. 31, 2006 and June 30, 2007, and the value of contracts no longer receiving hedge accounting. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of both the CD&M and the Generation business segments.

The anticipated timing of settlement (cash received) of the above contracts over each of the next five calendar years and thereafter are as follows:

		2007	2008	2009	2010	2011	2012 and thereafter	Total
Hedges	Prices actively quoted	$ (74.1)	$ (141.2)	$ (132.5)	$ (86.6)	$ (23.6)	$ (1.8)	**$ (459.8)**
	Prices based on models	(4.4)	(7.6)	(7.6)	(7.1)	(2.5)	-	**$ (29.2)**
		$ (78.5)	**$ (148.8)**	**$ (140.1)**	**$ (93.7)**	**$ (26.1)**	**$ (1.8)**	**$ (489.0)**
Non-Hedges	Prices actively quoted	$ 16.1	$ (7.3)	$ 0.4	$ -	$ -	$ -	**$ 9.2**
	Prices based on models	(3.7)	2.4	0.4	-	-	-	**$ (0.9)**
		$ 12.4	**$ (4.9)**	**$ 0.8**	**$ -**	**$ -**	**$ -**	**$ 8.3**
Grand total		**$ (66.1)**	**$ (153.7)**	**$ (139.3)**	**$ (93.7)**	**$ (26.1)**	**$ (1.8)**	**$ (480.7)**

Hedge transactions currently relate solely to Generation asset contracts consisting primarily of transactions under five years in duration. Contracts in excess of five years have been transacted with additional authorizations and strict controls.

Non-hedge transactions extending past 2007 are generally Generation asset-backed contracts that do not qualify for hedge accounting and have a low risk profile including long-term fixed for floating power swaps and heat rate swaps. Our Energy Trading activities are mainly transactions under 18 months in duration, thereby reducing credit risk and working capital requirements compared to longer term transactions.

Other Risk Management Assets and Liabilities

As a result of adopting new accounting standards on financial instruments certain risk management assets and liabilities used in hedging non-energy marketing transactions, debt, and the net investment in self-sustaining foreign subsidiaries were recorded at fair value.

The following table shows the balance sheet classifications for other risk management assets and liabilities separately by source of valuation:

Balance Sheet - Other	**June 30, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to non-energy trading
Risk management assets				
- Current	**$ 61.5**	**$ 3.2**	**$ 64.7**	$ 11.2
- Long-term	**81.5**	**-**	**$ 81.5**	43.2
Risk management liabilities				
- Current	**(8.9)**	**(1.1)**	**$ (10.0)**	(2.1)
- Long-term	**(16.1)**	**(15.7)**	**$ (31.8)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 118.0**	**$ (13.6)**	**$ 104.4**	$ 39.3

As a result of adopting new accounting standards on financial instruments risk management assets and liabilities receiving hedge accounting were recorded at fair value. The impact upon previously reported values is shown below along with changes in those values during the first six months of 2007:

	Hedges	**Non-Hedges**	**Total**
Net other risk management assets (liabilities) at Dec. 31, 2006 - *as reported*	50.1	(10.8)	39.3
Net other risk management assets (liabilities) at Dec. 31, 2006 - *fair value* [1]	58.0	(10.3)	47.7
Changes in values attributable to realization of contracts- (gains)/losses	2.9	1.5	4.4
Unrealized changes attributable to market price and other market changes -gains/(losses)	56.4	(4.9)	51.5
Unrealized new contracts entered into during the current period - gains/losses	0.7	0.1	0.8
Net other risk management assets (liabilities) at June 30, 2007 - *fair value*	118.0	(13.6)	104.4

[1] *As a result of adopting new accounting standards*

For the six months ended June 30, 2007, the fair value of our net risk management assets and liabilities associated with non-hedge positions decreased $3.3 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for non-hedge positions are reflected within interest expense.

For the six months ended June 30, 2007, the fair value of our net risk management assets and liabilities associated with hedge positions increased $60.0 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument, change in ownership of the foreign operation, or financial instrument being hedged.

Total Balances

The overall balance reported in risk management assets and liabilities are shown below:

Balance Sheet - Totals	June 30, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	43.8	64.7	108.5	61.0	11.2	72.2
- Long-term	(0.1)	81.5	81.4	21.9	43.2	65.1
Risk management liabilities						
- Current	(147.0)	(10.0)	(157.0)	(30.3)	(2.1)	(32.4)
- Long-term	(377.4)	(31.8)	(409.2)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	(480.7)	104.4	(376.3)	51.6	39.3	90.9

The corporation seeks to actively manage its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts and continually monitors these exposures after entering into these contracts. Detailed assessments are made of the credit quality of all counterparties and, where appropriate, corporate guarantees, and/or letters of credit are obtained to support the ultimate collection of these receivables. See Risk Factors and Risk Management in the MD&A in our annual report for the year ended Dec. 31, 2006 for further discussion of credit risk exposures and management thereof.

STATEMENTS OF CASH FLOWS

3 months ended June 30	2007	2006	Explanation
Cash and cash equivalents, beginning of period	**$ 78.5**	$ 89.5	
Provided by (used in):			
Operating activities	**227.6**	66.8	In 2007, cash inflows resulted from cash earnings of $171.9 million and positive cash flows from working capital of $55.7 million due to timing of collection of receivables.
			In 2006, cash inflows resulted from cash earnings of $152.9 million partially offset by $86.1 million of cash used in working capital to build coal inventory at Centralia Coal.
Investing activities	**(98.8)**	(5.1)	In 2007 cash outflows were primarily due to additions to property, plant and equipment of $139.5 million partially offset by proceeds on sale of assets of $23.3 million and restricted cash of $27.2 million.
			In 2006, cash outflows were primarily due to additions of property, plant and equipment of $68.7 million partially offset by unrealized gains from unwinding net investment hedges of $45.9 million.
Financing activities	**(160.2)**	(99.9)	In 2007, cash outflows were due to dividends on common shares of $50.5 million, repayment of long-term of $71.0 million, reduction of short-term debt of $25.2 million, and distributions to non-controlling interests of $19.7 million.
			In 2006, cash outflows were due to repayment of long-term debt of $12.6 million, distributions to subsidiaries' non-controlling interests of $16.9 million, dividends on common shares of $33.1 million, and a decrease in short-term debt of $39.2 million.
Translation of foreign currency cash	**6.0**	3.7	
Cash and cash equivalents, end of period	**$ 53.1**	$ 55.0	

6 months ended June 30	2007	2006	Explanation
Cash and cash equivalents, beginning of period	**$ 65.6**	$ 79.3	
Provided by (used in):			
Operating activities	**558.4**	267.1	In 2007, cash inflows were due to a cash earnings of $370.3 million and favorable change in working capital of $188.4 million due to collection of 2006 revenues in 2007.
			In 2006, cash inflows were due to cash earnings of $370.3 million partially offset by $103.2 million of cash used in working capital due to building coal inventory at Centralia coal.
Investing activities	**(153.8)**	(17.0)	In 2007, cash outflows were primarily due to additions of property, plant and equipment of $193.8 million and equity investment of $19.1 million partially offset by proceeds on sale of property, plant and equipment at $23.3 million and reduction in restricted cash of $36.6 million.
			In 2006, capital expenditures of $97.9 million offset realized gains on net investment hedges of $64.6 million, proceeds on sale of assets of $9.2 million, and decrease in equity investments of $8.2 million.
Financing activities	**(422.9)**	(277.2)	In 2007, cash outflows were due to dividends on common shares of $104.7 million, redemption of preferred securities of $175.0 million, reduction of long-term debt of $82.7 million, reduction of short-term debt of $32.3 million, and distributions paid to non-controlling interests of $40.5 million.
			In 2006, the cash used in financing activities increased due to repayment of long-term debt of $272.2 million, payment of distributions to non-controlling interests of $34.1 million, and dividend payments of $66.0 million partially offset by an increase in short-term debt of $86.3 million.
Translation of foreign currency cash	**5.8**	2.8	
Cash and cash equivalents, end of period	**$ 53.1**	$ 55.0	

Operating activities

For the three months ended June 30, 2007, funds generated from operations increased to $227.6 million from $66.8 million for the same period in 2006 due to higher cash earnings of $19.0 million and from favorable changes in non-cash working capital of $141.8 million due to cash being consumed in 2006 as we built coal inventory at Centralia Coal and from the timing of collections of accounts receivable in 2007. $1.2 million of costs were paid related to the closure of the Centralia Coal mine in the second quarter of 2007.

For the six months ended June 30, 2007, funds generated from operations increased to $558.4 million from $267.1 million due to cash being consumed in 2006 to build coal inventory at Centralia Coal and the timing of collection of 2006 receivables to $185 million. These accounts receivable balances in respect of November 2006 revenues were contractually scheduled to be paid, and were received, on Jan. 2, 2007. For the six months ended June 30, 2007, the corporation paid $24.2 million of costs related to the closure of the Centralia Coal mine.

Investing activities

For the three months ended June 30, 2007, cash used in investing activities was $98.8 million compared to $5.1 million for the same period in 2006. The increase in cash used was mainly due to increased capital spending of $70.8 million and the realization of gains on settling net investment hedges in 2006 of $45.9 million partially offset by proceeds on sale of equipment at Centralia of $23.3 million and positive inflows from restricted cash of $27.7 million.

For the six months ended June 30, 2007, cash used in investing activities was $153.8 million compared to $17.0 million in the same period in 2006 mainly due to higher additions to capital assets in 2007 of $95.9 million and the realized foreign exchange gains on net investments in the same period in 2006 of $64.6 million partially offset by higher proceeds from the sale of assets of $14.1 million and positive inflows from restricted cash of $37.4 million.

For the three and six months ended June 30, 2007, the corporation realized no cash outflows from the settlement of net investment hedges of foreign subsidiaries compared to cash inflows of $45.9 million and $64.6 million, respectively, for the same periods in 2006.

In 2007, the corporation has incurred a total of $72.6 million in capital expenditures relating to the Kent Hills, Sundance unit 4 uprate, and Keephills 3 projects. As well, the corporation has incurred $15.4 million in capital expenditures related to the rail handling and plant modifications at Centralia Coal.

For the six months ended June 30, 2007, the corporation realized $23.3 million from the sale of assets at our Centralia Mine operation.

Financing activities

For the three months ended June 30, 2007, cash used in financing activities increased to $160.2 million compared to $99.9 million for the same quarter of 2006. This increase in cash used was mainly due to increased repayment of long-term debt of $58.4 million and higher dividends paid of $17.4 million partially offset by lower repayment of short-term debt of $14.0 million.

For the six months ended June 30, 2007, cash used in financing activities increased $145.7 million mainly due to the payment of preferred securities in 2007 of $175 million, higher repayments on short-term debt of $118.6 million, and an increase in cash dividends paid and timing of those payments of $38.7 million.

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 company. Liquidity risk is managed to maintain sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner.

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

We have a $1.5 billion committed syndicated credit facility and approximately $0.4 billion of uncommitted credit facilities. At June 30, 2007, credit utilized under these facilities comprised of short-term debt of $330 million less cash on hand of $53 million and letters of credit of $693 million.

We have obligations to issue letters of credit to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At June 30, 2007, we had issued letters of credit totaling $693.3 million compared to $633.2 million at Dec. 31, 2006. This increase is due primarily to higher electricity prices in the Pacific Northwest. These letters secure certain amounts included in the corporation's balance sheet under "Risk Management Liabilities" and "Asset Retirement Obligations".

We expect that our ability to generate adequate cash flow from operations in the short-term and the long-term to maintain financial capacity and flexibility to provide for planned growth remains substantially unchanged since Dec. 31, 2006. In the third quarter we will only receive two month's worth of PPA revenue due to timing of contractually scheduled payments. Further, in the fourth quarter a payment relating to 2007 PPA revenues will not be received until January 2, 2008. However, the effect of timing of these payments is that we will receive 12 months of revenue in 2007.

On July 26, 2007, we had approximately 202.9 million common shares outstanding.

As at June 30, 2007 we had 1.6 million employee stock options outstanding with a weighted exercise price of $20.60. For the three months ended June 30, 2007, 0.3 million options with a weighted average exercise price of $19.12 were exercised resulting in 0.3 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $18.38.

For the six months ended June 30, 2007, 0.4 million options with a weighted average exercise price of $18.53 were exercised resulting in 0.4 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $17.15.

Guarantee contracts

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at June 30, 2007 was a maximum of $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at June 30, 2007, under the limited and unlimited guarantees, was $426.8 million as compared to $285.3 million at Dec. 31, 2006. The liabilities for these amounts are included in the corporation's balance sheet under "Risk Management Liabilities" and "Accounts payable and accrued liabilities".

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at June 30, 2007 was a maximum of $1.3 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at June 30, 2007, they are included in accounts payable and accrued liabilities.

The corporation has approximately $0.9 billion of credit available from its committed and uncommitted credit facilities to secure these exposures.

OUTLOOK

Outlook 2007 – 2009

We are seeing higher pricing in our key markets of Alberta and the Pacific Northwest. As a result our earnings per share ("EPS") projections have strengthened and growth in the double digits annually over the next several years is possible. This projection is based on pricing in Alberta of $65 - $75 CAD per MWh and in the Pacific Northwest of $45 - $55 USD per MWh over the 2007 – 2009 period.

Current outlook

The key factors affecting the financial results for the remainder of 2007 are the megawatt capacity in place, the availability of and production from generating assets, the margins applicable to non-contracted production, the costs of production, and the margins achieved on Energy Trading activities.

Production, availability and capacity

Generating capacity is expected to increase slightly due to the completion of an uprate at Unit 4 of our Sundance coal-fired facility in the latter portion of third quarter of 2007 with full commercial operations scheduled to begin in the fourth quarter. Production and availability in the third and fourth quarters are expected to slightly increase compared to the second quarter due to lower planned outages.

Power Prices

Year over year demand growth and delayed supply additions in Alberta will elevate electricity prices and spark spreads for the remainder of 2007. Prices are anticipated to be strong due to an expectation of a warmer and dryer summer combined with similar forced outage rates to 2006. Compared to 2006 for the Pacific Northwest, minimal load growth is anticipated but warmer temperatures and decreased hydro flows are expected to keep power prices and spark spreads higher for the rest of 2007. Ontario prices are also expected to strengthen compared to 2006 with an expectation of higher gas prices and a warmer summer.

Approximately 12 per cent of our gas fired facilities production and three per cent of our coal-fired facilities 2007 annual production have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes 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.

Fuel costs

Mining coal is subject to cost increases due to increased overburden removal, inflation, and diesel commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Coal costs in Alberta are expected to be $30 million higher than those in 2006. Fuel at Centralia Coal is purchased from an external supplier and costs are expected to be comparable with those seen year to date.

Exposure to gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term gas purchase contracts or corresponding offsets within revenues. Merchant gas facilities are exposed to the changes in spark spreads, as discussed in the Power Prices section. We have not entered into fixed commodity agreements for gas for these merchant plants as gas will be purchased coincident with spot pricing.

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 per MWh of installed capacity are anticipated to be comparable to those seen to date in the third quarter and lower compared to those seen to date in the fourth quarter due to the timing of planned maintenance activities.

Capital expenditures

Our capital expenditures are comprised of spending on sustaining our current operations and for growth activities. The two components are described in greater detail below.

Sustaining expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2007, our estimate for total sustaining capital expenditures, excluding Mexico, is between $350 million and $370 million, allocated among:

- $95 - $100 million for routine capital,
- $75 - $80 million for mining equipment,
- $100 - $105 million for equipment modifications at Centralia Coal and
- $80 - $85 million on planned maintenance as outlined in the following table:

	Coal	Gas and Hydro	Total
Capitalized	$65-70	$15-20	$80-90
Expensed	60-65	0-5	60-70
	$125-135	$15-25	$140-160
GWh lost	2,000-2,050	150-175	2,150-2,225

In 2007, we expect to lose approximately 2,150 to 2,225 GWh of production due to planned maintenance. During 2007, we have no significant planned maintenance activities at our Mexican operations.

Growth expenditures

For 2007, our growth capital expenditures are estimated to be between $255 million and $265 million on expenses related to the Sundance unit 4 uprate and the development projects at Keephills 3 and Kent Hills. Financing for these expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity.

Energy trading

Earnings from our energy trading segment are affected by prices in the market, the positions taken, and duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our objective is for proprietary trading to contribute between $50 million and $70 million in annual gross margin.

Exposure to fluctuations in foreign currencies

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

Net interest expense

Net interest expense for 2007 is expected to be comparable to those seen in the second quarter. However, higher interest rates and changes in the value of the Canadian dollar to the U.S. dollar could affect the amount of net interest expense incurred.

Liquidity and capital resources

With the anticipated increased volatility in power and gas markets, market trading opportunities are expected to increase, which can potentially cause the need for additional liquidity. To mitigate this liquidity risk, the corporation maintains a $1.5 billion committed credit facility and monitors exposures to determine any expected liquidity requirements.

Environmental legislation

On March 8, 2007 the Province of Alberta announced its proposed climate change legislation and regulations. The Alberta plan imposes a requirement of a 12 per cent GHG emission intensity reduction on major emitters commencing on July 1, 2007. Compliance can be achieved through direct emission reductions, payment into a Technology Fund at a fixed price, or through the purchase of offset credits from other projects within Alberta. Based on the current legislation, after flow through compliance costs are estimated to be approximately $3 million in 2007 and $7 million per year after that. This law was substantially enacted on June 27, 2007.

Mercury reduction requirements in Alberta are established at a 70 per cent reduction by 2010. TransAlta submitted its mercury control plan in March of 2007. We expect to formalize our investment plan in this new technology in late 2007 or early 2008.

On April 26, 2007, the Canadian government released details of its proposed environmental legislation. The federal plan calls for an 18 per cent reduction in GHG emission intensity starting in 2010, increasing to a 20 per cent absolute reduction requirement by 2020. Compliance can be achieved through direct emission reductions, payment into a technology fund at a fixed price, or through the purchase of offset credits. The proposed legislation also calls for a reduction in air pollutants such as sulphur dioxide, nitrous oxide, mercury, and particulates starting in the 2012 - 2015 period. Proposed reduction caps range from 45 per cent to 60 per cent. A number of material details in the federal plan are still to be determined, including its interaction with provincial programs, which are required to enable the corporation to make a reasonable determination of future compliance costs.

The PPA's for our Alberta based coal facilities contain change-in-law provisions that allow us the opportunity to recover compliance costs from the PPA customers.

Provincially, both Saskatchewan and Ontario introduced greenhouse gas programs during the quarter. However, neither provided any detail as to how the plans would affect power generation facilities other than Ontario's commitment to close coal units by 2014.

In the United States, the Washington State climate bill 6001 was enacted and will come into effect July 22, 2007. TransAlta operations will not be impacted by the bill's performance standards, provided the facilities do not change ownership or enter into contracts longer than five years. Additionally, further emissions requirements are being considered for our Centralia plant for mercury and nitrous oxide, however final determinations are several months away.

Federally, the US Government continues to contemplate a number of proposed greenhouse gas bills but to date no clear outcome or schedule is evident.

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 GAAP and therefore should not be considered in isolation or as an alternative to or more meaningful than, net income or cash flow from operating activities as determined in accordance with GAAP as an indicator of the corporation's 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.

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

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Gross margin	**$ 355.7**	$ 339.1	**$ 733.6**	$ 733.1
Operating expenses	**(265.2)**	(263.4)	**(504.8)**	(503.4)
Operating income	**90.5**	75.7	**228.8**	229.7
Foreign exchange loss (gain)	**4.4**	(1.2)	**4.5**	(1.8)
Net interest expense	**(35.7)**	(38.0)	**(73.0)**	(78.5)
Gain on sale of equipment	**11.7**	-	**11.7**	-
Equity (loss) income	**(2.1)**	2.0	**(11.0)**	1.0
Earnings before non-controlling interests and income taxes	**68.8**	38.5	**161.0**	150.4
Non-controlling interests	**5.8**	4.0	**21.8**	22.9
Earnings before income taxes	**63.0**	34.5	**139.2**	127.5
Income tax expense (recovery)	**5.8**	(51.9)	**25.8**	(28.1)
Net earnings	**$ 57.2**	$ 86.4	**$ 113.4**	$ 155.6

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 prior periods' results. Because we believe the turbine impairment charge recorded in the first quarter of 2006 would otherwise affect the comparability of our results from period to period, we have excluded that item to calculate earnings on a comparable basis.

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Earnings on a comparable basis	**$ 41.9**	$ 31.1	**$ 98.1**	$ 106.5
Sale of assets at Centralia	**7.6**	-	**7.6**	-
Tax rate change	**7.7**	55.3	**7.7**	55.3
Turbine impairment, net of tax	**-**	-	**-**	(6.2)
Net earnings	**$ 57.2**	$ 86.4	**$ 113.4**	$ 155.6
Weighted average common shares outstanding in the period	**202.8**	200.5	**202.8**	200.3
Earnings on a comparable basis per share	**$ 0.20**	$ 0.15	**$ 0.48**	$ 0.53

Free cash flow is intended to demonstrate the amount of cash we have available to invest in capital growth initiatives, repay recourse debt or repurchase common shares.

The contractually scheduled payments from 2006 have been excluded from the calculation of free cash flow as the timing of this payment is dependant upon certain calendar holidays in the month of December and this change due to timing does not occur on a frequent basis. The payment of Centralia mine closure costs have also been excluded as they are one-time in nature. Sustaining capital expenditures is total capital expenditures per the statement of cash flow less $59.7 million we have invested in growth projects in the second quarter of 2007. For the six months ended June 30, 2007, we have invested $72.6 million in growth projects.

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

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Cash flow from operating activities	**$ 227.6**	$ 66.8	**$ 558.4**	$ 267.1
Add (Deduct):				
Sustaining capital expenditures	**(79.8)**	(65.6)	**(121.2)**	(91.2)
Dividends on common shares	**(50.5)**	(33.1)	**(104.7)**	(66.0)
Distribution to subsidiaries' non-controlling interest	**(19.7)**	(16.9)	**(40.5)**	(34.1)
Non-recourse debt repayments	**(37.2)**	(17.0)	**(45.9)**	(25.5)
Timing of contractualy scheduled payments from 2006	**-**	-	**(185.0)**	-
Centralia closure costs	**1.2**	-	**24.2**	-
Cash flows from equity investments	**10.0**	6.5	**8.0**	7.2
Free cash flow	**$ 51.6**	$ (59.3)	**$ 93.3**	$ 57.5

Cash flows from equity investments represent operational cash flow from our equity subsidiaries less sustaining and growth capital expenditures.

SELECTED QUARTERLY INFORMATION

(In millions of Canadian dollars except per share amounts)

	Q3 2006	Q4 2006	Q1 2007 (Restated)	Q2 2007
Revenue	**$ 684.0**	**$ 779.8**	**$ 709.9**	**$ 665.5**
Net earnings (loss)	**35.3**	**(146.0)**	**56.2**	**57.2**
Basic earnings (loss) per common share	**0.18**	**(0.72)**	**0.28**	**0.28**
Diluted earnings (loss) per common share	**0.18**	**(0.72)**	**0.28**	**0.28**

	Q3 2005	Q4 2005	Q1 2006	Q2 2006
Revenue	$ 722.9	$ 810.1	$ 733.7	$ 599.0
Net earnings	51.2	59.9	69.2	86.4
Basic earnings per common share	0.26	0.30	0.35	0.43
Diluted earnings per common share	0.26	0.30	0.35	0.43

ADJUSTMENT TO REPORTED FIRST QUARTER RESULTS

Net earnings for the three months ended June 30, 2007 have been derived from the net earnings for the six months ended June 30, 2007 and from the adjusted earnings for the three months ended March 31, 2007. The net earnings for the three months ended March 31, 2007 have been adjusted, in this filing, to reflect the correction of an error in the previously issued financial statements. Following the release of first quarter earnings, management detected a discrepancy in the amount of unrealized gain recorded on certain contracts that no longer qualified for hedge accounting. The discrepancy arose after implementing an upgrade to our trading system which resulted in some of the contracts that no longer qualify for hedge accounting to be double counted. As a result, the fair values of these additional contracts were incorrectly reclassified from Other Comprehensive Income to the income statement. The net effect of this error was that in the previously issued financial statements net earnings should be reduced by $9.8 million, which is net of taxes of $4.0 million. Other comprehensive income for the three months ended March 31, 2007 should therefore be increased by a corresponding after-tax amount of $9.8 million. The resulting EPS for the first quarter of 2007 would be $0.28 per share, compared to the reported $0.33 per share, a further reduction of $0.05 per share. Earnings for the three months ended June 30, 2007 have been presented taking account of this correction and earnings for the six months ended June 30, 2007 are not affected. A solution has been implemented which will prevent this situation from arising in the future. In addition, management has added additional controls to this process, including additional management review and oversight.

Based upon this evaluation, our President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have concluded that our disclosure controls and procedures are effective.

In coming to the conclusion that the Company's disclosure controls and procedures and the Company's internal control over financial reporting were effective as of June 30, 2007, management considered, among other things, the impact of the above noted error the financial statements and the effectiveness of internal controls in this area. Management has concluded that the control deficiency resulting in this error in previously issued financial statements did not constitute a material weakness in disclosure controls and procedures, or internal control over financial reporting, as of June 30, 2007. In addition, the company has implemented modifications to enhance its internal controls in this area. These changes have not affected, nor are they reasonably likely to materially affect, our internal control over financial reporting.

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934, 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. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2007, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level. These certificates can be found at www.sedar.com.

TransAlta completed its implementation of the enhancement to its accounting system and associated processes which were used to prepare the second quarter results. Changes to our accounting system were facilitated through our existing controls and processes.

FORWARD-LOOKING STATEMENTS

This MD&A and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on TransAlta Corporation's beliefs and assumptions based on information available at the time the assumption was made. In some cases, forward-looking statements can be identified by terms such as ‘may’, ‘will’, ‘believe’, ‘expect’, ‘potential’, ‘enable’, ‘continue’ or other comparable terminology. The forward-looking statements relate to, among other things, statements regarding the anticipated business prospects and financial performance of TransAlta. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties and other important factors that could cause the corporation’s actual performance to be materially different from those projected, including those material risks discussed in this MD&A under the heading ‘Outlook’ and in the MD&A in our annual report for the year ended Dec. 31, 2006 under the heading ‘Risk Factors and Risk Management’. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs associated with environmental compliance, overall costs, cost and availability of fuel to produce electricity, the speed and degree of competition entering the market; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions where TransAlta Corporation operates; results of financing efforts; changes in counterparty risk; and the impact of accounting standards issued by Canadian standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements which is given as of the date it is expressed in this MD&A or otherwise and TransAlta undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2007**	2006	**2007** *(Restated, Note 1)*	2006
Revenues	**$ 665.5**	$ 599.0	**$ 1,375.4**	$ 1,332.7
Trading purchases	**(53.9)**	(18.7)	**(95.2)**	(63.1)
Fuel and purchased power *(Note 1)*	**(255.9)**	(241.2)	**(546.6)**	(536.5)
Gross margin	**355.7**	339.1	**733.6**	733.1
Operations, maintenance and administration	**159.5**	155.5	**294.6**	288.5
Depreciation and amortization *(Note 1)*	**100.4**	102.3	**199.4**	203.8
Taxes, other than income taxes	**5.3**	5.6	**10.8**	11.1
Operating expenses	**265.2**	263.4	**504.8**	503.4
Operating income	**90.5**	75.7	**228.8**	229.7
Foreign exchange gain (loss)	**4.4**	(1.2)	**4.5**	(1.8)
Gain on sale of equipment *(Note 7)*	**11.7**	-	**11.7**	-
Net interest expense *(Note 6)*	**(35.7)**	(38.0)	**(73.0)**	(78.5)
Equity (loss) income	**(2.1)**	2.0	**(11.0)**	1.0
Earnings before non-controlling interests and income taxes	**68.8**	38.5	**161.0**	150.4
Non-controlling interests	**5.8**	4.0	**21.8**	22.9
Earnings before income taxes	**63.0**	34.5	**139.2**	127.5
Income tax expense (recovery)	**5.8**	(51.9)	**25.8**	(28.1)
Net earnings	**$ 57.2**	$ 86.4	**$ 113.4**	$ 155.6
Common share dividends	**(50.7)**	(50.1)	**(101.4)**	(100.0)
Retained earnings				
Opening balance	**715.5**	885.4	**710.0**	866.1
Closing balance	**$ 722.0**	$ 921.7	**$ 722.0**	$ 921.7
Weighted average number of common shares outstanding in the period	**202.8**	200.5	**202.8**	200.3
Net earnings per share, basic and diluted	**$ 0.28**	$ 0.43	**$ 0.55**	$ 0.77

See accompanying notes

TRANSALTA CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE LOSS
(in millions of Canadian dollars)

	3 months ended June 30, 2007	6 months ended June 30, 2007	3 months ended June 30, 2006	6 months ended June 30, 2006
Net earnings	**$ 57.2**	**$ 113.4**	86.4	155.6
Other comprehensive loss				
Losses on translating net assets of self-sustaining foreign operations	**(88.0)**	**(104.1)**	(50.3)	(43.6)
Gains on financial instruments designated as hedges of self-sustaining foreign operations	**109.0**	**123.6**	54.5	44.8
Tax expense	**(20.7)**	**(21.2)**	(5.10)	(4.20)
	88.3	**102.4**	49.40	40.60
Gains (losses) on translation of self-sustaining foreign operations	**0.3**	**(1.7)**	(0.9)	(3.0)
Losses on derivatives designated as cash flow hedges	**(118.8)**	**(245.3)**	-	-
Tax recovery	**37.7**	**77.5**	-	-
Losses on derivatives designated as cash flow hedges	**(81.1)**	**(167.8)**	-	-
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period	**(5.1)**	**2.2**	-	-
Tax expense (recovery)	**1.2**	**(0.6)**	-	-
	(3.9)	**1.6**	-	-
Other comprehensive loss	**(84.7)**	**(167.9)**	(0.9)	(3.0)
Comprehensive loss	**$ (27.5)**	**$ (54.5)**	$ 85.5	$ 152.6

See accompanying notes

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

Unaudited	June 30 2007	Dec. 31 2006
ASSETS	*(Restated, Note 1)*	*(Restated, Note 1)*
Current assets		
Cash and cash equivalents	**$ 53.1**	$ 65.6
Accounts receivable	**388.2**	618.3
Prepaid expenses	**23.1**	9.1
Risk management assets *(Notes 1, 3 and 4)*	**108.5**	72.2
Future income tax assets	**60.7**	25.8
Income taxes receivable	**48.8**	47.6
Inventory	**41.8**	53.0
Current portion of other assets *(Note 1)*	**-**	5.4
	724.2	897.0
Restricted cash *(Note 5)*	**284.2**	347.8
Investments	**162.7**	154.5
Long-term receivables	**32.0**	32.2
Property, plant and equipment		
Cost	**8,379.3**	8,190.1
Accumulated depreciation	**(3,376.9)**	(3,148.2)
	5,002.4	5,041.9
Assets held for sale, net *(Note 7)*	**44.8**	109.8
Goodwill	**130.8**	137.5
Intangible assets	**247.9**	292.1
Future income tax assets	**357.6**	294.0
Risk management assets *(Notes 1, 3 and 4)*	**81.4**	65.1
Other assets *(Notes 1 and 4)*	**88.5**	88.2
Total assets	**$ 7,156.5**	$ 7,460.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt *(Note 3)*	**$ 330.2**	$ 361.9
Accounts payable and accrued liabilities	**370.5**	441.9
Risk management liabilities *(Notes 1, 3 and 4)*	**157.0**	32.4
Income taxes payable	**6.5**	22.3
Future income tax liabilities	**18.2**	19.9
Dividends payable	**48.1**	51.5
Deferred credits and other current liabilities *(Notes 1 and 8)*	**41.0**	48.5
Current portion of long-term debt - recourse *(Notes 3 and 6)*	**319.7**	205.0
Current portion of long-term debt - non-recourse *(Notes 3 and 6)*	**39.5**	44.7
Preferred securities *(Note 6)*	**-**	175.0
	1,330.7	1,403.1
Long-term debt - recourse *(Notes 3 and 6)*	**1,499.4**	1,681.5
Long-term debt - non-recourse *(Notes 3 and 6)*	**248.2**	289.6
Deferred credits and other long-term liabilities *(Notes 1 and 8)*	**375.3**	410.4
Future income tax liabilities	**671.4**	698.6
Risk management liabilities *(Notes 1, 3 and 4)*	**409.2**	14.0
Non-controlling interests	**516.4**	535.0
Common shareholders' equity		
Common shares *(Note 12)*	**1,793.6**	1,782.4
Retained earnings	**722.0**	710.0
Accumulated other comprehensive loss *(Note 2)*	**(409.7)**	(64.5)
Total shareholders' equity	**2,105.9**	2,427.9
Total liabilities and shareholders' equity	**$ 7,156.5**	$ 7,460.1

Contingencies *(Notes 13 and 14)*
Commitments *(Notes 4, 15, and 16)*

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

Unaudited	3 months ended June 30 **2007**	3 months ended June 30 2006	6 months ended June 30 **2007**	6 months ended June 30 2006
Operating activities			*(Restated, Note 1)*	
Net earnings	**$ 57.2**	$ 86.4	**$ 113.4**	$ 155.6
Depreciation and amortization *(Note 9)*	**100.1**	107.1	**200.0**	217.4
Gain on sale of assets	**(11.7)**	-	**(11.7)**	-
Non-controlling interests	**5.8**	4.0	**21.8**	22.9
Asset retirement obligation accretion *(Note 8)*	**5.9**	6.0	**11.9**	11.0
Asset retirement costs settled *(Note 8)*	**(4.3)**	(1.0)	**(7.5)**	(1.8)
Future income taxes	**5.5**	(38.6)	**(1.7)**	(37.3)
Unrealized losses (gains) from risk management activities	**20.8**	(11.8)	**39.6**	(0.4)
Foreign exchange (gain) loss	**(4.4)**	1.2	**(4.5)**	1.8
Equity loss (income)	**2.1**	(2.0)	**11.0**	(1.0)
Other non-cash items	**(5.1)**	1.6	**(2.3)**	2.1
	171.9	152.9	**370.0**	370.3
Change in non-cash operating working capital balances	**55.7**	(86.1)	**188.4**	(103.2)
Cash flow from operating activities	**227.6**	66.8	**558.4**	267.1
Investing activities				
Additions to property, plant and equipment	**(139.5)**	(68.7)	**(193.8)**	(97.9)
Proceeds on sale of property, plant and equipment *(Note 7)*	**23.3**	9.2	**23.3**	9.2
Equity investment	**(9.1)**	8.5	**(19.1)**	8.2
Restricted cash *(Note 5)*	**27.2**	(0.5)	**36.6**	(0.8)
Acquisition of Wailuku Hydro facility	**-**	-	**-**	(1.2)
Realized foreign exchange gain on net investments	**-**	45.9	**-**	64.6
Proceeds on sale of long-term investments	**-**	3.0	**-**	3.0
Other	**(0.7)**	(2.5)	**(0.8)**	(2.1)
Cash flow used in investing activities	**(98.8)**	(5.1)	**(153.8)**	(17.0)
Financing activities				
(Decrease) / Increase in short-term debt	**(25.2)**	(39.2)	**(32.3)**	86.3
Repayment of long-term debt *(Note 6)*	**(71.0)**	(12.6)	**(257.7)**	(272.2)
Dividends paid on common shares	**(50.5)**	(33.1)	**(104.7)**	(66.0)
Net proceeds on issuance of common shares *(Note 12)*	**5.4**	3.4	**10.1**	6.0
Distributions to subsidiaries' non-controlling interests	**(19.7)**	(16.9)	**(40.5)**	(34.1)
Decrease / (Increase) in advances to TransAlta Power	**0.8**	(1.5)	**2.2**	2.8
Cash flow used in financing activities	**(160.2)**	(99.9)	**(422.9)**	(277.2)
Cash flow from operating, investing and financing activities	**(31.4)**	(38.2)	**(18.3)**	(27.1)
Effect of translation on foreign currency cash	**6.0**	3.7	**5.8**	2.8
Decrease in cash and cash equivalents	**(25.4)**	(34.5)	**(12.5)**	(24.3)
Cash and cash equivalents, beginning of period	**78.5**	89.5	**65.6**	79.3
Cash and cash equivalents, end of period	**$ 53.1**	$ 55.0	**$ 53.1**	$ 55.0
Cash taxes paid	**$ 15.1**	$ 1.0	**$ 37.0**	$ 24.1
Cash interest paid	**$ 51.5**	$ 54.0	**$ 77.4**	$ 88.7

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 (consisting of normal recurring adjustments and accruals) that are, in the opinion of management, necessary for a fair presentation of the results for the interim periods.

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. Margins are also typically increased in the second quarter due to increased hydro production resulting from spring run-off and rainfall in the Canadian and U.S. markets.

These unaudited interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") using the same accounting policies as those used in the corporation's most recent annual consolidated financial statements, except as explained below.

Adjustment to First Quarter Results

Net earnings for the three months ended June 30, 2007 have been derived from the net earnings for the six months ended June 30, 2007 and from the adjusted earnings for the three months ended March 31, 2007. The net earnings for the three months ended March 31, 2007 have been adjusted, in this filing, to reflect the correction of an error in the previously issued financial statements. Following the release of first quarter earnings, management detected a discrepancy in the amount of unrealized gain recorded on certain contracts that no longer qualified for hedge accounting. The discrepancy arose after implementing an upgrade to our trading system which resulted in some of the contracts that no longer qualify for hedge accounting to be double counted. As a result, the fair values of these additional contracts were incorrectly reclassified from Other Comprehensive Income to the income statement. The net effect of this error was that in the previously issued financial statements net earnings should be reduced by $9.8 million, which is net of taxes of $4.0 million. Other comprehensive income for the three months ended March 31, 2007 should therefore be increased by a corresponding after-tax amount of $9.8 million. The resulting EPS for the first quarter of 2007 would be $0.28 per share, compared to the reported $0.33 per share, a further reduction of $0.05 per share. Earnings for the three months ended June 30, 2007 have been presented taking account of this correction and earnings for the six months ended June 30, 2007 are not affected. A solution has been implemented which will prevent this situation from arising in the future. In addition, management has added additional controls to this process, including additional management review and oversight.

Depreciation Expense

Depreciation expense in the second quarter of 2007 is higher compared to the same period in 2006 due to the reclassification of accretion expense from cost of sales to depreciation of $4.4 million. For active mines, accretion expense is included in fuel and purchased power. However, as the Centralia Mine is now considered inactive accretion expense related to the Centralia Mine is now included as part of depreciation expense. In 2006, $1.9 million was recorded in the second quarter and $3.8 million was recorded for the year in fuel expense related to accretion expense incurred at the Centralia Mine.

Significant Accounting Policy Changes

Financial Instruments

On Jan. 1, 2007, TransAlta adopted four new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1530, *Comprehensive Income*, Section 3855, *Financial Instruments – Recognition and Measurement*, Section 3861, *Financial Instruments – Disclosure and Presentation*, and Section 3865, *Hedges*. We adopted these standards retroactively with an adjustment of opening accumulated other comprehensive income ("AOCI") solely related to accumulated losses on the translation of self-sustaining foreign operations.

To present comparable 2006 balance sheet figures, prior year balances were reclassified. Short-term and long-term risk management assets were increased by $11.2 million and $43.2 million respectively, and current and long-term portions of other assets were reduced by the corresponding amounts. Short-term and long-term risk management liabilities were increased by $2.1 million and $13.0 million respectively, and current and long-term portions of deferred credits and other long-term liabilities were decreased by the corresponding amounts. $64.5 million of cumulative losses on the translation of self-sustaining foreign subsidiaries was reclassified as the opening balance of AOCI.

Comprehensive Income

Section 1530 introduces comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). OCI represents changes in shareholders' equity during a period arising from transactions and changes in prices, markets, interest rates, and exchange rates and includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, net of hedging activities, and changes in the fair value of the effective portion of cash flow hedging instruments. TransAlta has included in the interim consolidated financial statements a consolidated statement of comprehensive income for the changes in these items during the second quarter of 2007, while the cumulative changes in OCI are included in AOCI, which is presented as a new category of shareholders' equity on the consolidated balance sheet.

The majority of the changes were reflected in the value of CD&M risk management assets and liabilities as well as in financial instruments used as hedges of debt and net investment of self-sustaining foreign subsidiaries. The impact of adopting these standards to our Dec. 31, 2006 balance sheet is outlined below:

	Price Risk Assets		Price Risk Liabilities		
	Current	Long-Term	Current	Long-Term	Net
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 - *as reported*	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of CD&M net risk management assets (liabilities) outstanding at Dec. 31, 2006	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

The gross and net of tax impact of adopting these standards to the opening balance of AOCI are outlined below:

Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$	90.9
Fair value of CD&M net risk management liabilities outstanding at Dec. 31, 2006		(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Dec. 31, 2006		47.7
Total fair value of risk liabilities		(173.5)
Change in fair value		(264.4)
Tax		(87.1)
Adjustment to opening Accumulated Other Comprehensive loss from fair values	$	(177.3)
Cumulative Translation Adjustment		(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$	(241.8)

Financial Instruments – Recognition and Measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the consolidated balance sheet when we become a party to the contractual provisions of the financial instrument or non-financial derivative contract. Under this standard, all financial instruments are required to be measured at fair value upon initial recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition and amortized using the effective interest rate method. Financial liabilities are removed from the financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability.

Financial assets and financial liabilities held-for-trading are measured at fair value with changes in those fair values recognized in net earnings. Financial assets held-to-maturity, loans and receivables, and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market are measured at cost.

Derivative instruments are recorded on the consolidated balance sheet at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net earnings with the exception of the effective portion of (1) derivatives designated as effective cash flow hedges or (2) hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation which are recognized in OCI.

Section 3855 also provides an entity the option to designate a financial instrument as held-for-trading (the fair value option) on its initial recognition or upon adoption of the standard, even if the financial instrument, other than loans and receivables, was not acquired or incurred principally for the purpose of selling or repurchasing it in the near term. An instrument that is classified as held for-trading by way of this fair value option must have reliable fair values and satisfy one of the following criteria (i) when doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities, or recognizing gains and losses on them on a different basis; or (ii) it belongs to a group of financial assets, financial liabilities or both which are managed and evaluated on a fair value basis in accordance with our risk management strategy, and are reported to senior management personnel on that basis.

Our financial assets and liabilities designated as held-for-trading are primarily related to our energy trading segment.

Other significant accounting implications arising upon the adoption of Section 3855 include the use of the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost, and the recognition of the inception fair value of the obligation undertaken in issuing a guarantee that meets the definition of a guarantee pursuant to Accounting Guideline 14, Disclosure of Guarantees ("AcG-14"). No subsequent re-measurement at fair value is required unless the financial guarantee qualifies as a derivative. If the financial guarantee meets the definition of a derivative it is re-measured at fair value at each balance sheet date and reported as a derivative in other assets or other liabilities, as appropriate.

In addition, Section 3855 requires that an entity must select an accounting policy of either expensing debt issue costs as incurred or applying them against the carrying value of the related asset or liability. TransAlta is currently applying all debt transaction costs against the carrying value of the debt.

Hedges

Section 3865 specifies the criteria that must be satisfied in order for hedge accounting to be applied and the accounting for each of the permitted hedging strategies: fair value hedges, cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as an effective hedge, or the derivative is terminated or sold, or upon the sale or early termination of the hedged item.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for unrealized gains or losses attributable to the hedged risk and recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. When hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified immediately to net earnings when the hedged item is sold or early terminated, or hedged anticipated transaction is not probable to occur.

In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in net earnings. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a dilution or sale of the net investment; or reduction in equity of the foreign operation as a result of dividend distributions.

Impact upon adoption of Sections 1530, 3855 and 3865

The transition adjustments attributable to the re-measurement of financial assets and financial liabilities at fair value, other than hedging instruments designated as cash flow hedges or hedges of foreign currency exposure of net investment in self-sustaining foreign operations available for sale financial assets, were recognized in opening retained earnings (the value of which was nil) as at Jan. 1, 2007. Adjustments arising from re-measuring financial assets classified as available-for sale at fair value were recognized in opening AOCI as at that date.

For hedging relationships existing prior to adopting Section 3865 that continue to qualify for hedge accounting under the new standard, the transition accounting is as follows: (i) Fair value hedges – any gain or loss on the hedging instrument was recognized in opening retained earnings and the carrying amount of the hedged item was adjusted by the cumulative change in fair value attributable to the designated hedged risk and was also included in opening retained earnings; (ii) Cash flow hedges and hedges of net investments in self-sustaining foreign operations – the effective cumulative portion of any gain or loss on the hedging instrument was recognized in AOCI and the cumulative ineffective portion was included in opening retained earnings (see Note 2).

We have recorded the following transition adjustments in our consolidated financial statements: recognition in AOCI of $177.3 million, net of taxes, related to the cumulative losses on the effective portion of our cash flow hedges that are now required to be recognized under Sections 3855 and 3865. In addition, we have reclassified to AOCI, $64.5 million of net foreign currency gains that were previously presented as a separate item in shareholders' equity. We have applied this adjustment retroactively, with restatement, to the statement of other comprehensive income. There was no impact to net earnings or earnings per shares of prior periods as a result of adopting these standards.

Variable Interest Entities ("VIEs")

On Sept. 15, 2006, the Emerging Issues Committee issued Abstract No. 163, *Determining the Variability to be Considered in Applying AcG-15* ("EIC-163"). EIC-163 provides additional clarification on how to analyze and consolidate VIEs when transactions take place to reduce the variability in the entity. EIC-163 became effective for us on Jan. 1, 2007, and its implementation does not have a material impact upon our consolidated financial position or results of operations.

Future accounting changes

Capital Disclosures and Financial Instruments – Disclosures and Presentation

On Dec. 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, *Capital Disclosures*, Handbook Section 3862, *Financial Instruments – Disclosures*, and Handbook Section 3863, *Financial Instruments – Presentation*. These new standards will be effective for us on Jan. 1, 2008.

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. The new Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments — Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks. We are currently assessing the impact of these new standards on our financial statements.

Inventories

In March 2007, the CICA issued Section 3031, *Inventories*, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards ("IFRS"). This standard will not have a material affect upon TransAlta's financial statements.

International Financial Reporting Standards

In 2005 the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. The AcSB has indicated that Canadian firms will need to begin reporting under IFRS by the first quarter of 2011 with appropriate comparative data from the prior year. Under IFRS, the primary audience is capital markets and as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed.

On July 3, 2007, the Securities and Exchange Commission published for public comment a proposal to eliminate the current requirement that foreign private issuers filing their financial statements using IFRS also file a reconciliation to US GAAP.

TransAlta is currently assessing the impact of IFRS upon our financial statements.

2. SHAREHOLDER'S EQUITY

Statement of Shareholder's Equity
(in millions of Canadian dollars except per share amounts)

	Common shares	Retained earnings	Accumulated other comprehensive income	Total shareholders equity
Balance, Dec. 31, 2006 *(Note 1)*	1,782.4	710.0	(64.5)	2,427.9
Change in accounting policy (*Note 1*)	-	-	(177.3)	(177.3)
Balance, Dec. 31, 2006, as adjusted	1,782.4	710.0	(241.8)	2,250.6
Net income for the 6 months ended June 30, 2007	-	113.4	-	113.4
Common shares issued (dividends declared)	11.2	(101.4)	-	(90.2)
Unrealized gains and losses on translating financial statements of self-sustaining foreign operations	-	-	(1.7)	(1.7)
Gains and losses on derivatives designated as cash flow hedges	-	-	(167.8)	(167.8)
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period	-	-	1.6	1.6
Balance, June 30, 2007	**$ 1,793.6**	**$ 722.0**	**$ (409.7)**	**$ 2,105.9**

3. FAIR VALUES 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, willing parties who are under no compulsion to act. Fair values are determined by reference to prices in active markets for that instrument to which we have access. In the absence of an active market, we determine fair values based on valuation models, such as option pricing models and discounted cash flow analysis, using observable market-based inputs.

Fair values determined using valuation models require the use of assumptions concerning the amount and timing of estimated future cash flows. In determining those assumptions, we look primarily to external readily observable market inputs including factors such as electricity prices, gas prices, and anticipated market growth. In limited circumstances, we use input parameters that are not based on observable market data and we believe that using possible alternative assumptions will not result in significantly different fair values.

(a) Accounting for changes in fair value of financial instruments during the period

As described in Note 1, financial instruments classified as held-for trading are carried at fair value on the consolidated balance sheet. Any changes in the fair values of financial instruments classified as held-for-trading are recognized in net earnings except those contracts that are part of effective hedge relationships.

Carrying value and Fair value of selected Financial Instruments

While most financial assets and liabilities are carried at fair value, the following table provides a comparison of carrying values as at June 30, 2007, and Dec. 31, 2006, for selected financial instruments:

Carrying value and fair value of financial instruments as at June 30, 2007

	Classified as held-for-trading	Per Consolidated Balance Sheet	Total Fair Value
Risk management assets			
- Short Term	108.5	108.5	108.5
- Long Term	81.4	81.4	81.4
Total risk management assets	189.9	189.9	189.9
Risk management liabilities			
- Short Term	157.0	157.0	157.0
- Long Term	409.2	409.2	409.2
Total price risk management liabilities	566.2	566.2	566.2

We adopted Sections 1530, 3855, and 3865 effective Jan. 1, 2007. We adopted these standards retroactively with an adjustment of opening AOCI.

Carrying value and fair value of financial instruments as at Dec. 31, 2006

	Classified as held-for-trading	Total Carrying Value	Per Consolidated Balance Sheet	Total Fair Value [1]
Risk management assets				
- Short Term	72.2	72.2	72.2	112.2
- Long Term	65.1	65.1	65.1	138.8
Total risk management assets	137.3	137.3	137.3	251.0
Risk management liabilities				
- Short Term	32.4	32.4	32.4	126.1
- Long Term	14.0	14.0	14.0	298.4
Total risk management liabilities	46.4	46.4	46.4	424.5

1: Differences between fair value and carrying value are a result of cash flow hedges that were not previously recorded, but have been accounted for under Section 3865

(b) Hedging activities

We use derivatives and non-derivative financial instruments to manage our exposures to interest, commodity prices, currency, credit, and other market risks. When derivatives are used to manage our own exposures, we determine for each derivative whether hedge accounting can be applied. Where hedge accounting can be applied, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposure of a net investment in a self-sustaining foreign operation. The derivative must be highly effective in accomplishing the objective of offsetting either changes in the fair value or cash flows attributable to the hedged risk both at inception and over the life of the hedge. If it is determined that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

Fair value hedges

We use interest rate swaps to hedge our exposure to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates. We also use foreign exchange contracts to hedge foreign currency denominated assets and liabilities. See Note 6 for a further description of the terms and rates of these swaps.

For the quarter ended June 30, 2007, the ineffective portion of fair value hedges recognized in net income amounted to a pre-tax unrealized loss of $nil.

Cash flow hedges

We use forward sale and purchase contracts, as well as foreign exchange contracts, 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.

For the quarter ended June 30, 2007, a pre-tax unrealized loss of $118.8 million was recorded in OCI for the effective portion of the cash flow hedges, and an unrealized loss of $5.1 million was reclassified to net income. For the six months ended June 30, 2007, a pre-tax unrealized loss of $245.3 million was recorded in OCI for the effective portion of the cash flow hedges, and an unrealized loss of $2.2 million was reclassified to net income. A net unrealized loss of $nil was recognized in income for the ineffective portion.

At June 30, 2006, the corporation's cash flow hedges of the forecasted sales and the forecasted purchases for the corporation's plants resulted in the recognition of an after-tax unrealized gain in OCI of $1.7 million.

For the 6 months ending June 30, 2007, the corporation's cash flow hedges resulted in no after-tax gain or loss due to hedge ineffectiveness. A $40.0 million loss has been recognized year to date related to certain contracts which no longer qualify for hedge accounting due to reduced production forecasts at Centralia Coal.

Over the next 12 months, the corporation estimates that $105.5 million of after-tax losses will be reclassified from AOCI to OCI. These estimates assume constant gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings, either positive or negative, will be for the next 12 months.

Net investment hedges

We use foreign exchange contracts and foreign currency-denominated liabilities to manage our foreign currency exposures to net investments in self-sustaining foreign operations having a functional currency other than the Canadian dollar. We also have foreign denominated expenses to assist in managing foreign currency exposures on earnings from self-sustaining foreign operations.

For the three months ended June 30, 2007, the net gain of $0.3 million, and for the six months ended June 30, 2007, the net loss of $1.7million relating to our net investment in foreign operations was recognized in OCI.

The following table presents the fair values of derivative instruments categorized by their hedging relationships, as well as derivatives that are not designated in hedging relationships.

Fair value of derivative instruments as at June 30, 2007

(in thousands of dollars)	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated in a hedging relationship	**Total**
Financial Assets					
Derivative instruments	16.7	3.6	126.3	43.3	**189.9**
Financial Liabilities					
Derivative instruments	(15.6)	(501.1)	(1.0)	(48.5)	**(566.2)**

We have designated our US dollar denominated debt with a face value of $600 million USD as a part of the hedge of our self-sustaining foreign operations.

4. RISK MANAGEMENT ASSETS AND LIABILITIES

Our risk management assets and liabilities are comprised of two major types: (1) those that are used in the CD&M and Generation segments in relation to trading activities and certain contracting activities and (2) those used in hedging non-energy trading transactions, debt, and the net investment in self-sustaining foreign subsidiaries.

The overall balances reported in risk management assets and liabilities are shown below:

Balance Sheet - Totals	June 30, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	43.8	64.7	108.5	61.0	11.2	72.2
- Long-term	(0.1)	81.5	81.4	21.9	43.2	65.1
Risk management liabilities						
- Current	(147.0)	(10.0)	(157.0)	(30.3)	(2.1)	(32.4)
- Long-term	(377.4)	(31.8)	(409.2)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	(480.7)	104.4	(376.3)	51.6	39.3	90.9

Energy Trading

The hedge and non-hedge values of other risk management assets and liabilities for energy trading are included on the consolidated balance sheets as follows:

Balance Sheet - Energy Trading	**June 30, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to energy trading
Risk management assets				
- Current	**$ 6.5**	**$ 37.3**	**$ 43.8**	$ 61.0
- Long-term	**(2.9)**	**2.8**	**(0.1)**	21.9
Risk management liabilities				
- Current	**(116.4)**	**(30.6)**	**(147.0)**	(30.3)
- Long-term	**(376.2)**	**(1.2)**	**(377.4)**	(1.0)
Net risk management assets (liabilities) outstanding	**$ (489.0)**	**$ 8.3**	**$ (480.7)**	$ 51.6

The following table illustrates the impact of adopting new standards for financial instruments and the movements in the fair value of the corporation's energy trading net risk management assets and liabilities separately by source of valuation during the six months ended June 30, 2007:

	Hedges		**Non-Hedges**		
Change in fair value of net assets (liabilities)	**Mark to Market**	**Mark to Model**	**Mark to Market**	**Mark to Model**	**Total**
Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	**$ 51.6**
Net risk management assets outstanding at Dec. 31, 2006 - *fair value* [1]	(253.0)	(19.8)	52.7	(1.1)	**(221.2)**
Contracts realized, amortized or settled during the period	(1.5)	1.8	(27.7)	(1.0)	**(28.4)**
Changes in values attributable to market price and other market changes	(180.3)	(11.2)	(5.7)	(2.5)	**(199.7)**
New contracts entered into during the current period	(42.3)	-	7.2	3.7	**(31.4)**
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	-	(17.3)	-	**-**
Net risk management assets (liabilities) outstanding at June 30, 2007	**$ (459.8)**	**$ (29.2)**	**$ 9.2**	**$ (0.9)**	**$ (480.7)**

[1] *As a result of adopting new accounting standards*

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

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

		2007	2008	2009	2010	2011	2012 and thereafter	Total
Hedges	Prices actively quoted	$ (74.1)	$ (141.2)	$ (132.5)	$ (86.6)	$ (23.6)	$ (1.8)	**$ (459.8)**
	Prices based on models	(4.4)	(7.6)	(7.6)	(7.1)	(2.5)	-	**$ (29.2)**
		$ (78.5)	**$ (148.8)**	**$ (140.1)**	**$ (93.7)**	**$ (26.1)**	**$ (1.8)**	**$ (489.0)**
Non-Hedges	Prices actively quoted	$ 16.1	$ (7.3)	$ 0.4	$ -	$ -	$ -	**$ 9.2**
	Prices based on models	(3.7)	2.4	0.4	-	-	-	**$ (0.9)**
		$ 12.4	**$ (4.9)**	**$ 0.8**	**$ -**	**$ -**	**$ -**	**$ 8.3**
Grand total		**$ (66.1)**	**$ (153.7)**	**$ (139.3)**	**$ (93.7)**	**$ (26.1)**	**$ (1.8)**	**$ (480.7)**

The corporations fixed price proprietary trading positions at June 30, 2007 and December 31, 2006, were as follows:

Units (000s)	Electricity (MWh)	Natural Gas (GJ)	Transmission (MWh)	Coal (Tonnes)	Emissions (Tonnes)
Fixed price payor, notional amounts, June 30, 2007	**21,885**	**88,471**	**1,854**	**535**	**6**
Fixed price payor, notional amounts, Dec. 31, 2006	13,944	20,289	1,479	-	-
Fixed price receiver, notional amounts, June 30, 2007	**22,404**	**90,273**	**-**	**535**	**15**
Fixed price receiver, notional amounts, Dec. 31, 2006	21,536	26,231	-	-	-
Maximum term in months, June 30, 2007	**27**	**13**	**82**	**12**	**2**
Maximum term in months, Dec. 31, 2006	33	16	24	-	-

Other Risk Management Assets and Liabilities

The hedge and non-hedge values of non-energy trading assets and liabilities included on the consolidated balance sheets are as follows:

Balance Sheet - Other	**June 30, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to non-energy trading
Risk management assets				
- Current	**$ 61.5**	**$ 3.2**	**$ 64.7**	$ 11.2
- Long-term	**81.5**	**-**	**$ 81.5**	43.2
Risk management liabilities				
- Current	**(8.9)**	**(1.1)**	**$ (10.0)**	(2.1)
- Long-term	**(16.1)**	**(15.7)**	**$ (31.8)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 118.0**	**$ (13.6)**	**$ 104.4**	$ 39.3

The following table illustrates the impact of adopting new standards for financial instruments and the movements in the fair value of the corporation's other net risk management assets and liabilities separately by source of valuation during the six months ended June 30, 2007:

	Hedges	**Non-Hedges**	**Total**
Net other risk management assets (liabilities) at Dec. 31, 2006 - *as reported*	50.1	(10.8)	39.3
Net other risk management assets (liabilities) at Dec. 31, 2006 - *fair value* [1]	58.0	(10.3)	47.7
Changes in values attributable to realization of contracts- (gains)/losses	2.9	1.5	4.4
Unrealized changes attributable to market price and other market changes -gains/(losses)	56.4	(4.9)	51.5
Unrealized new contracts entered into during the current period - gains/losses	0.7	0.1	0.8
Net other risk management assets (liabilities) at June 30, 2007 - *fair value*	118.0	(13.6)	104.4

[1] *As a result of adopting new accounting standards*

Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument, change in ownership of the foreign operation, or financial instrument being hedged.

5. RESTRICTED CASH

Restricted cash is mostly comprised of an investment in Notes held in trust as security for a subsidiary's obligation under a credit derivative agreement. Should the subsidiary fail to perform its obligations under this agreement, the counterparty has the right to retain the Notes in satisfaction of the subsidiary's obligation. The Notes earn interest at six month LIBOR and mature in 2016.

The change in restricted cash is outlined below:

Balance, Dec. 31, 2006	$	347.8
Change in foreign exchange rates		(26.9)
Amount returned to TransAlta		(36.7)
Balance, June 30, 2007	$	284.2

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Amounts outstanding	**June 30, 2007**			Dec. 31, 2006		
	Fair Value [1]	**Cost**	**Interest** [2]	Fair Value	Cost	Interest [2]
Debentures, due 2007 to 2033	**$ 1,153.9**	**$ 1,146.1**	**6.1%**	$ 1,161.3	$ 1,146.4	6.1%
Senior Notes, US$600.0 million	**620.5**	**636.1**	**6.3%**	683.6	693.2	6.3%
Non-recourse debt	**287.7**	**287.7**	**7.7%**	334.3	334.3	7.7%
Notes payable - Windsor plant, due 2007 to 2014	**44.7**	**44.7**	**7.4%**	46.9	46.9	7.4%
Preferred securities, due in 2050	**-**	**-**	**-**	175.0	175.0	7.8%
	2,106.8	**2,114.6**		2,401.1	2,395.8	
Less: current portion	**(359.2)**	**(359.2)**		(424.7)	(424.7)	
	$ 1,747.6	**$ 1,755.4**		$ 1,976.4	$ 1,971.1	

[1] Fair value debentures and notes currently being utilized as Net Investment Hedge.

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

The corporation has converted fixed interest rate debt with rates ranging from 5.75 per cent to 6.90 per cent to floating rates through the use of receive fixed pay floating interest rate swaps. The interest rate swaps have maturities ranging from 2011 to 2013.

On Jan. 2, 2007, the corporation redeemed its Preferred Securities which had an aggregate principal of $175.0 million. As at Dec. 31, 2006 the Preferred Securities were presented as a liability on the consolidated balance sheets. Distributions on these Preferred Securities are included in interest expense as shown below:

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Interest on long-term debt	**$ 36.8**	$ 34.7	**$ 75.6**	$ 68.8
Interest on short-term debt	**6.0**	2.5	**12.5**	6.2
Interest on preferred securities	**-**	3.4	**-**	6.8
Interest income	**(6.6)**	(2.6)	**(14.3)**	(3.3)
Capitalized interest	**(0.5)**	-	**(0.8)**	-
Net interest expense	**$ 35.7**	$ 38.0	**$ 73.0**	$ 78.5

The corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2007 relates to the corporation's investment in Keephills 3 and Kent Hills.

7. ASSETS HELD FOR SALE

As a result of the decision to stop mining at Centralia, all associated mining and reclamation equipment is being held for sale. All equipment has been recorded at the lower of net book value or anticipated realized proceeds. These assets are included in the Generation segment. During the second quarter some of this equipment had been retained for reclamation activities ($20.2 million), transferred to the Highvale mine for use in production of coal inventory ($8.6 million), and allocated to potential future Westfields Development ($16.7 million) and has been reclassified to property, plant, and equipment. The decision to retain equipment for use in reclamation activities at the Centralia Mine and in operations at the Highvale Mine was arrived at as the economics of retaining these assets was greater than the potential cash proceeds from disposing these assets.

During the second quarter of 2007, equipment with a net book value of $11.6 million was sold for proceeds of $23.3 million; the remainder of these assets are anticipated to be sold in 2007.

In 2006 we sold excess turbines in inventory for net proceeds of $9.2 million which equaled their net book value.

8. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

	June 30, 2007	Dec. 31, 2006
Asset retirement obligation	**$ 321.4**	$ 328.5
Deferred revenues and other	**15.6**	19.7
Power purchase arrangement in limited partnership	**26.0**	27.1
Accrued benefit liability	**53.3**	58.0
Centralia mine closure costs	**-**	25.6
	$ 416.3	$ 458.9
Less: current portion	**(41.0)**	(48.5)
	$ 375.3	$ 410.4

For the six months ended June 30, 2007, the corporation paid $24.2 million of costs related to the closure of the Centralia Coal mine. The difference between actual cash payments and the balance as at Dec. 31, 2006 is due to the strengthening of the Canadian dollar relative to the US dollar.

The reconciliation between the opening and closing asset retirement obligation balances is provided below:

Balance, Dec. 31, 2006	$ 328.5
Liabilities incurred in period	1.6
Liabilities settled in period	(7.5)
Accretion expense	11.9
Revisions in estimated cash flows	(1.0)
Change in foreign exchange rates	(12.1)
Balance, June 30, 2007	**$ 321.4**

The amount of any asset retirement obligations due beyond one year are included in deferred credits and other long-term liabilities on the consolidated balance sheets. Any amount anticipated to be settled in the next 12 months is included in the current portion of deferred credits and long term liabilities on the consolidated balance sheets.

The Company has a right to recover a portion of future asset retirement costs. The estimated present value of these payments has been recorded as a long-term receivable.

9. SEGMENTED DISCLOSURES

I. Each business segment assumes responsibility for its operating results measured to operating income.

3 months ended June 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Revenues	**$ 595.1**	**$ 70.4**	**$ -**	**$ 665.5**
Trading purchases	**-**	**$ (53.9)**	**-**	**(53.9)**
Fuel and purchased power *(Note 2)*	**(255.9)**		**-**	**(255.9)**
Gross margin	**339.2**	**16.5**	**-**	**355.7**
Operations, maintenance and administration	**128.7**	**8.3**	**22.5**	**159.5**
Depreciation and amortization	**96.9**	**0.3**	**3.2**	**100.4**
Taxes, other than income taxes	**5.3**	**-**	**-**	**5.3**
Intersegment cost allocation	**6.6**	**(6.6)**	**-**	**-**
Operating expenses	**237.5**	**2.0**	**25.7**	**265.2**
Operating income (loss)	**$ 101.7**	**$ 14.5**	**$ (25.7)**	**$ 90.5**
Gain on sale of equipment				**11.7**
Foreign exchange gain				**4.4**
Net interest expense				**(35.7)**
Equity income				**(2.1)**
Earnings before income taxes and non-controlling interests				**$ 68.8**

3 months ended June 30, 2006	Generation	CD&M	Corporate	Total
Revenues	$ 554.6	$ 44.4	$ -	$ 599.0
Trading purchases	-	(18.7)	-	(18.7)
Fuel and purchased power	(241.2)	-	-	(241.2)
Gross margin	313.4	25.7	-	339.1
Operations, maintenance and administration	128.8	8.3	18.4	155.5
Depreciation and amortization	98.8	0.4	3.1	102.3
Taxes, other than income taxes	5.6	-	-	5.6
Intersegment cost allocation	7.0	(7.0)	-	-
Operating expenses	240.2	1.7	21.5	263.4
Operating income (loss)	$ 73.2	$ 24.0	$ (21.5)	$ 75.7
Corporate allocations	18.7	2.8	(21.5)	-
Operating income (loss)	$ 54.5	$ 21.2	$ -	75.7
Foreign exchange loss				(1.2)
Net interest expense				(38.0)
Equity income				2.0
Earnings before income taxes and non-controlling interests				$ 38.5

Six months ended June 30, 2007	**Generation**	**CD&M**	**Corporate**	**Total**
Revenues	**$ 1,253.2**	**$ 122.2**	**$ -**	**$ 1,375.4**
Trading purchases	**-**	**$ (95.2)**	**-**	**(95.2)**
Fuel and purchased power *(Note 2)*	**(546.6)**	**-**	**-**	**(546.6)**
Gross margin	**706.6**	**27.0**	**-**	**733.6**
Operations, maintenance and administration	**232.7**	**16.9**	**45.0**	**294.6**
Depreciation and amortization	**192.3**	**0.7**	**6.4**	**199.4**
Taxes, other than income taxes	**10.7**	**-**	**0.1**	**10.8**
Intersegment cost allocation	**13.7**	**(13.7)**	**-**	**-**
Operating expenses	**449.4**	**3.9**	**51.5**	**504.8**
Operating income (loss)	**$ 257.2**	**$ 23.1**	**$ (51.5)**	**$ 228.8**
Gain on sale of equipment				**11.7**
Foreign exchange gain				**4.5**
Net interest expense				**(73.0)**
Equity loss				**(11.0)**
Earnings before income taxes and non-controlling interests				**$ 161.0**

Six months ended June 30, 2006		Generation		CD&M		Corporate		Total
Revenues	$	1,234.6	$	98.1	$	-	$	1,332.7
Trading purchases		-		(63.1)		-		(63.1)
Fuel and purchased power		(536.5)		-		-		(536.5)
Gross margin		698.1		35.0		-		733.1
Operations, maintenance and administration		233.2		16.4		38.9		288.5
Depreciation and amortization		196.9		0.7		6.2		203.8
Taxes, other than income taxes		11.1		-		-		11.1
Intersegment cost allocation		13.9		(13.9)		-		-
Operating expenses		455.1		3.2		45.1		503.4
Operating income	$	243.0	$	31.8	$	(45.1)	$	229.7
Foreign exchange loss								(1.8)
Net interest expense								(78.5)
Equity loss								1.0
Earnings from continuing operations before income taxes and non-controlling interests							$	150.4

II. Selected balance sheet information

June 30, 2007		Generation		Energy Trading		Corporate		Total
Goodwill	**$**	**101.3**	**$**	**29.5**	**$**	**-**	**$**	**130.8**
Total segment assets	**$**	**5,638.0**	**$**	**183.1**	**$**	**1,335.4**	**$**	**7,156.5**

Dec. 31, 2006								
Goodwill	$	108.0	$	29.5	$	-	$	137.5
Total segment assets	$	6,159.3	$	185.0	$	1,115.8	$	7,460.1

III. Selected cash flow information

3 months ended June 30, 2007		Generation		Energy Trading		Corporate		Total
Capital expenditures	**$**	**133.9**	**$**	**1.0**	**$**	**4.6**	**$**	**139.5**

3 months ended June 30, 2006								
Capital expenditures	$	61.5	$	-	$	7.2	$	68.7

6 months ended June 30, 2007		Generation		Energy Trading		Corporate		Total
Capital expenditures	**$**	**185.0**	**$**	**1.5**	**$**	**7.3**	**$**	**193.8**

6 months ended June 30, 2006								
Capital expenditures	$	87.0	$	1.7	$	9.2	$	97.9

The reconciliation between depreciation expense on the income statement and statement of cash flows is presented below:

IV. Reconciliation
Depreciation and amortization expense per statement of cash flows

	3 months ended June 30		6 months ended June 30	
	2007	2006	**2007**	2006
Depreciation and amortization expense for reportable segments	**$ 100.4**	$ 102.3	**$ 199.4**	$ 203.8
Mining equipment depreciation, included in fuel and purchased power	**6.7**	14.5	**13.7**	28.8
Accretion expense, included in depreciation and amortization expense	**(5.9)**	(6.0)	**(11.9)**	(11.0)
Other	**(1.1)**	(3.7)	**(1.2)**	(4.2)
Depreciation and amortization expense per statements of cash flows	**$ 100.1**	$ 107.1	**$ 200.0**	$ 217.4

10. EMPLOYEE FUTURE BENEFITS

The corporation has registered pension plans in Canada, Mexico and the U.S. covering substantially all employees of the corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada, there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plans has been closed for new employees for all periods presented. Costs recognized in the period are presented below:

3 months ended June 30, 2007	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 0.9**	**$ 0.3**	**$ 0.3**	**$ 1.5**
Interest cost	**5.0**	**0.5**	**0.3**	**5.8**
Expected return on plan assets	**(6.2)**	**-**	**-**	**(6.2)**
Experience loss	**-**	**0.1**	**0.1**	**0.2**
Past service costs	**0.1**	**-**	**-**	**0.1**
Amortization of net transition (asset) obligation	**(2.3)**	**0.1**	**-**	**(2.2)**
Curtailment	**-**	**-**	**0.2**	**0.2**
Settlement	**0.1**	**-**	**-**	**0.1**
Defined benefit (income) expense	**(2.4)**	**1.0**	**0.9**	**(0.5)**
Defined contribution option expense of registered pension plan	**3.6**	**-**	**-**	**3.6**
Net expense	**$ 1.2**	**$ 1.0**	**$ 0.9**	**$ 3.1**

3 months ended June 30, 2006	Registered	Supplemental	Other	Total
Current service cost	$ 1.2	$ 0.3	$ 0.3	$ 1.8
Interest cost	5.0	0.5	0.4	5.9
Expected return on plan assets	(6.3)	-	-	(6.3)
Experience loss	0.8	0.3	0.1	1.2
Past service costs	0.1	(0.1)	0.1	0.1
Amortization of net transition (asset) obligation	(2.3)	0.1	-	(2.2)
Defined benefit (income) expense	(1.5)	1.1	0.9	0.5
Defined contribution option expense of registered pension plan	4.2	-	-	4.2
Net expense	$ 2.7	$ 1.1	$ 0.9	$ 4.7

6 months ended June 30, 2007	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 1.9**	**$ 0.6**	**$ 0.7**	**$ 3.2**
Interest cost	**10.1**	**1.1**	**0.6**	**11.8**
Expected return on plan assets	**(12.3)**	**-**	**-**	**(12.3)**
Experience loss	**0.1**	**0.2**	**0.1**	**0.4**
Past service costs	**0.1**	**(0.1)**	**0.1**	**0.1**
Amortization of net transition (asset) obligation	**(4.6)**	**0.2**	**-**	**(4.4)**
Curtailment	**-**	**-**	**0.2**	**0.2**
Settlement	**0.2**	**-**	**-**	**0.2**
Defined benefit (income) expense	**(4.5)**	**2.0**	**1.7**	**(0.8)**
Defined contribution option expense of registered pension plan	**9.4**	**-**	**-**	**9.4**
Net expense	**$ 4.9**	**$ 2.0**	**$ 1.7**	**$ 8.6**

6 months ended June 30, 2006	Registered	Supplemental	Other	Total
Current service cost	$ 2.3	$ 0.6	$ 0.7	$ 3.6
Interest cost	10.0	1.0	0.7	11.7
Expected return on plan assets	(12.7)	-	-	(12.7)
Experience loss	1.5	0.5	0.2	2.2
Past service costs	0.1	(0.1)	0.1	0.1
Amortization of net transition (asset) obligation	(4.6)	0.2	-	(4.4)
Defined benefit (income) expense	(3.4)	2.2	1.7	0.5
Defined contribution option expense of registered pension plan	9.7	-	-	9.7
Net expense	$ 6.3	$ 2.2	$ 1.7	$ 10.2

11. INCOME TAXES

As a result of the Tax Fairness Plan, Canadian corporate tax rates were reduced by 0.5 per cent beginning in 2011, resulting in a reduction of tax expense in the second quarter of $7.7 million which reflected the impact of these changes on prior year's earnings.

In 2006, as a result of Alberta and Federal budgets, comparable tax rates were reduced resulting in reduction of tax expense of $55.3 million which reflected the impact of these changes on prior year earnings.

12. 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 June 30, 2007, the corporation had 202.8 million (Dec. 31, 2006 – 202.4 million) common shares issued and outstanding. During the three months ended June 30, 2007, 0.3 million (2006 – 1.0 million) shares were issued for net proceeds of $5.4 million (2006 – $23.0 million). During the six months ended June 30, 2007, 0.5 million (2006 – 1.0 million) shares were issued for net proceeds of $10.1 million (2006 – $23.0 million).

During the three and six months ended June 30, 2006, 0.8 million and 1.5 million shares, respectively, were issued under the Dividend Reinvestment and Share Purchase Plan for gross proceeds of $17.2 million and $34.5 million, respectively. Effective Jan. 1, 2007 shares are purchased on the open market.

B. Stock options

At June 30, 2007, the corporation had 1.6 million outstanding employee stock options (Dec. 31, 2006 – 2.2 million). For the three months ended June 30, 2007, 0.3 million options with a weighted average exercise price of $19.12 were exercised resulting in 0.3 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $18.38.

For the six months ended June 30, 2007, 0.4 million options with a weighted average exercise price of $18.53 were exercised resulting in 0.4 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $17.15.

13. 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 will have a material adverse effect on the corporation, taken as a whole.

14. PRIOR PERIOD REGULATORY DECISION

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the Federal Power Act ("FPA"), Federal Energy Regulatory Commission ("FERC") established a claim of approximately US$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange ("PX") and the California Independent System Operator ("ISO") during the Oct. 2, 2000 through June 20, 2001 period (the "Main Refund Transactions"). TransAlta has provided US$46 million to account for refund liabilities relating to Main Refund Transactions.

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006 TransAlta filed for rehearing of FERC's rejection. FERC has not yet issued a decision on rehearing.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (the "Summer Transactions"). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources ("CDWR") referred to as CERS (the "CERS Transactions"). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

15. GUARANTEES

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at June 30, 2007 was a maximum of $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at June 30, 2007, under the limited and unlimited guarantees, was $426.8 million as compared to $285.3 million at Dec. 31, 2006. The liabilities for these amounts are included in the corporation's balance sheet under "Risk Management Liabilities" and "Accounts payable and accrued liabilities".

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at June 30, 2007 was a maximum of $1.3 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at June 30, 2007, they are included in accounts payable and accrued liabilities.

A subsidiary of the corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include US$262 million of loans made to subsidiaries of the corporation.

The corporation has approximately $0.9 billion of credit available from its committed and uncommitted credit facilities to secure these exposures.

16. COMMITMENTS

On June 21, 2007, TransAlta Utilities Corporation, a subsidiary of the corporation, has entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal to the Keephills 3 joint venture project. The total dragline purchase costs include approximately $104 million USD for the purchase of the equipment, and an additional $29 million CAD for the assembly and commissioning of the dragline, for a total of approximately $150 million CAD, with final payments for goods and services due by May 2010. Total anticipated payments under this agreement in 2007 are approximately $15 million USD.

Keephills 3 plant construction costs via the Keephills 3 Limited Partnership are anticipated to be approximately $1.3 billion with final payments for goods and services due by 2011. TransAlta proportionate share is approximately $650 million.

TransAlta signed a 25 year long-term contract in early 2007 with New Brunswick Power Distribution and Customer Service Corporation to provide 75 MW of wind power. We will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills") with an estimated capital cost of $130 million for the design, construction, transportation and assembly of the wind turbine generator towers and ancillary equipment. Commercial operations are expected to begin by the end of 2008, at which time final payments are also expected.

17. RELATED PARTY TRANSACTIONS

On March 8, 2006, TransAlta Cogeneration LP ("TA Cogen") entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen at market prices during planned maintenance at Sheerness plant in the second quarter of

2006. The swap was settled in the second quarter of 2006 and did not have a material effect on the financial statements.

In August 2006, TransAlta entered into an agreement with CE Gen, a corporation jointly controlled by TransAlta and MidAmerican, a subsidiary of Berkshire Hathaway, whereby TransAlta buys available power from certain CE Gen subsidiaries at a fixed price. In addition, CE Gen has entered into contracts with related parties to provide administrative and maintenance services.

For the period November 2002 to November 2012, TA Cogen entered into various transportation swap transactions with a wholly owned subsidiary of TransAlta, TEC. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to Sheerness, which is operated by Canadian Utilities. 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 three of its plants over the period of the swap. The notional gas volume in the transaction was the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party, therefore TransAlta has no risk other than counterparty risk.

18. SUBSEQUENT EVENT

Power purchase agreement

On July 19, 2007, we amended our power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation to increase capacity under the agreement from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills wind power project will also increase by $40 million to $170 million. We also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site. Under the purchase and sale agreement, TransAlta will acquire Canadian Hydro’s Fairfield Hill wind power site, including the option to develop the site at a future date.

SUPPLEMENTAL INFORMATION

(Annualized)			June 30 2007		Dec. 31 2006
Closing market price		$	**26.75**	$	26.64
Price range (last 12 months)	High	$	**28.44**	$	26.91
	Low	$	**23.76**	$	20.22
Debt/invested capital (including non recourse debt)			**44.0%**		44.0%
Debt/invested capital (excluding non recourse debt)			**40.9%**		40.5%
Return on common shareholders' equity			**7.3%**		9.4%
Return on invested capital			**6.7%**		6.6%
Book value per share		$	**12.40**	$	12.31
Cash dividends per share		$	**1.00**	$	1.00
Price/earnings ratio (times)			**29.4 x**		22.9 x
Dividend payout ratio			**109.2%**		86.0%
Dividend coverage (times)			**3.9 x**		2.4 x
Dividend Yield			**3.7%**		3.8%
Cash Flow to Debt			**28.1%**		26.2%

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt – cash and interest-earning investments) / (debt + preferred securities + non-controlling interests + common equity)
Return on common shareholders' equity = net earnings excluding gain on discontinued operations / average of opening and closing common equity
Return on invested capital = (earnings before non-controlling interests and income taxes + net interest expense) / average annual invested capital
Book value per share = common shareholders' equity / common shares outstanding
Price/earnings ratio = current year's close / basic earnings per share from continuing operations
Cash flow to total debt = cash flow from operations before changes in working capital / two-year average of total debt
Dividend payout = dividends / net earnings excluding gain on discontinued operations
Dividend coverage = cash flow from operating activities / common share dividends
Dividend yield = dividend per common share / current period's close price

GLOSSARY OF KEY TERMS

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, whether or not it is actually generating electricity.

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

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

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

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.

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

Megawatt - 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 fuel).

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