TRANSALTA CORPORATION

SECOND QUARTER REPORT FOR 2008

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 24 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 six months ended June 30, 2008 and 2007, 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, 2007. 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 31, 2008. 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 Commercial Operations & Development ("COD"). Our segments are supported by a corporate group that provides finance, treasury, legal, regulatory, environmental, health, and safety, sustainable development, corporate communications, government relations, information technology, human resources, internal audit, and other administrative support.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items 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	
	2008	2007	**2008**	2007
Availability (%)	**79.3**	83.6	**85.5**	85.9
Production (GWh)	**10,652**	11,497	**23,878**	24,194
Revenue	**$ 708**	$ 612	**$ 1,511**	$ 1,281
Gross margin[1]	**$ 376**	$ 356	**$ 809**	$ 734
Operating income[1]	**$ 93**	$ 91	**$ 282**	$ 229
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113
Basic and diluted earnings per common share	**$ 0.24**	$ 0.28	**$ 0.40**	$ 0.56
Comparable earnings per share[1]	**$ 0.25**	$ 0.20	**$ 0.74**	$ 0.48
Cash flow from operating activities	**$ 171**	$ 168	**$ 408**	$ 499
Cash dividends declared per share	**$ 0.27**	$ 0.25	**$ 0.54**	$ 0.50

1 Gross margin, Operating income and Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 22 of this MD&A for a further discussion of these items, including a reconciliation to net earnings.

	6 months ended June 30, 2008	Year ended Dec. 31, 2007
Total assets	**$ 7,554**	$ 7,179
Total long-term financial liabilities	**$ 3,534**	$ 2,880

AVAILABILITY & PRODUCTION

Availability for the three months ended June 30, 2008 decreased compared to the same period in 2007 due to higher planned outages at the Centralia Thermal plant (“Centralia Thermal”) as a result of planned maintenance and equipment modifications, and higher unplanned outages at the Alberta Thermal plants (“Alberta Thermal”), partially offset by lower planned outages at Alberta Thermal.

Availability for the six months ended June 30, 2008 was comparable to the same period in 2007.

Production for the second quarter of 2008 decreased compared to the same period in 2007 primarily as a result of planned maintenance, equipment modifications, and economic dispatching at Centralia Thermal, higher unplanned outages at Alberta Thermal, partially offset by lower planned outages at Alberta Thermal and higher merchant volumes due to the uprate at our Sundance facility.

Production for the six months ended June 30, 2008 decreased compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal, partially offset by higher merchant volumes due to the uprate at our Sundance facility.

NET EARNINGS

A reconciliation of net earnings is presented below:

	3 months ended June 30, 2008	6 months ended June 30, 2008
Net earnings, 2007	$ 57	$ 113
(Decrease) / Increase in Generation gross margins	(16)	21
Mark-to-market movements - Generation	7	21
Increase in COD gross margins	29	33
Increase in operations, maintenance, and administration costs	(18)	(18)
Gain on sale of mining equipment in 2007	(12)	(7)
Decrease in net interest expense	2	6
Decrease / (increase) in equity loss	2	(86)
Decrease in income tax expense	2	8
Other	(6)	(11)
Net earnings, 2008	**$ 47**	**$ 80**

Generation gross margins, net of mark-to-market movements, decreased for the three months ended June 30, 2008 due to higher unplanned outages at Alberta Thermal and higher planned outages at Centralia Thermal, partially offset by favourable pricing across the fleet, lower planned outages at Alberta Thermal, and higher merchant volumes due to the uprate at our Sundance facility.

For the six months ended June 30, 2008, Generation gross margins increased due to favourable pricing and higher merchant volumes, partially offset by higher unplanned outages at Alberta Thermal and unfavourable foreign exchange rates.

For the three and six months ended June 30, 2008, COD gross margins increased relative to the same period in 2007 due to strong trading results in both the Eastern and Western regions in the second quarter.

Operations, maintenance, and administration ("OM&A") costs for the three and six months ended June 30, 2008 increased compared to the same periods in 2007 primarily due to increased stock-based compensation costs, and higher planned maintenance costs as a result of more planned maintenance activities in 2008.

For the three months ended June 30, 2008, net interest expense remained comparable to the same period in 2007, but decreased slightly for the comparable six months ended June 30, 2008.

For the six months ended June 30, 2008, equity loss increased due to the writedown of our Mexican investment.

Income taxes decreased for the three months ended June 30, 2008 compared to the same period in 2007 due to lower pre-tax income partially offset by the tax rate reduction in 2007. For the six months ended June 30, 2008, income taxes decreased from the same period in 2007 due to the tax recovery on the writedown of our Mexican investment in the first quarter of 2008 partially offset by an increase in pre-tax earnings.

CASH FLOW

Cash flow from operating activities for the three months ended June 30, 2008 remained comparable to the same period in 2007. For the six months ended June 30, 2008 cash flow from operating activities decreased due to more favourable changes in operating working capital in 2007 and from the timing of income tax installments.

Due to contractual timing, a $116 million payment relating to 2007 Power Purchase Agreement ("PPA") revenues was not received until Jan. 2, 2008. In 2007, a contractual payment of $185 million related to 2006 PPA revenues was not received until Jan. 2, 2007.

For the three and six months ended June 30, 2008, we have received, respectively, three and seven payments under the PPAs, consistent with the same periods in 2007.

Free cash flow[1] for the three and six months ended June 30, 2008 decreased compared to the same periods in 2007 mainly due to higher sustaining capital expenditures.

SIGNIFICANT EVENTS

Three months ended June 30, 2008

Expansion at Summerview

On May 27, 2008, we announced a 66 megawatt ("MW") expansion at our Summerview wind farm located in Southern Alberta near Pincher Creek. The total capital cost of the project is estimated at $123 million with commercial operations expected to commence by the first quarter of 2010.

Bond Offering

On May 6, 2008, we announced we priced an offering of U.S.$500 million of 6.65 per cent senior notes due in 2018. The net proceeds from the offering are being used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

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1 Free cash flow is not defined under Canadian GAAP. Refer to page 23 of this MD&A for a further discussion of this item, including a reconciliation to cash flow from operating activities.

Normal Course Issuer Bid ("NCIB") Program Renewed

On May 5, 2008, we announced plans to renew our NCIB program until May 5, 2009. We received the approval to purchase, for cancellation, up to 19.9 million of our common shares representing 10 per cent of our 199 million common shares issued and outstanding as at April 23, 2008. Purchases will be made on the open market through the Toronto Stock exchange ("TSX") at the market price of such shares at the time of acquisition.

Uprate at Sundance Facility

On April 21, 2008, we announced a 53 MW efficiency uprate at Unit 5 of our Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009.

Clean Energy Technology Investments

On April 4, 2008, the Government of Canada announced a $125 million fund to support the development of Carbon Capture and Storage ("CCS") technologies from the oil sands and from coal-fired electricity plants. We have applied for funding under this government initiative to support our pilot of chilled ammonia carbon capture technology being developed in conjunction with Alstom Canada.

Carbon Capture and Storage Project

On April 3, 2008, we announced an agreement with Alstom Canada to pilot chilled ammonia carbon capture technology at one of our Alberta Thermal units, contingent on acquiring adequate industry and government support.

Six months ended June 30, 2008

Mexico Business

On Feb. 20, 2008, we announced the sale of our Mexican operations to InterGen Global Ventures B.V. ("InterGen") for U.S.$303.5 million. Due to the process needed to adjust various contracts related to gas pricing regulatory changes in Mexico, the transaction is expected to close before the end of the third quarter of 2008. We recorded a charge to the first quarter earnings of $65 million, net of tax, to reflect the estimated difference between the net carrying value and anticipated net sale price of these assets. The gross charge of $93 million is recorded in equity loss.

Blue Trail Wind Power Project

On Feb. 13, 2008, we announced plans to design, build, and operate Blue Trail, a 66 MW wind power project in southern Alberta. The capital cost of the project is estimated at $115 million. Commercial operations are expected to commence in the fourth quarter of 2009.

Dividend Policy and Dividend Increase

On March 25, 2008, our Board of Directors announced the adoption of a formal dividend policy which targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings.

On Feb. 1, 2008, our Board of Directors approved an increase to the annual dividend from $1.00 to $1.08 per share.

Greenhouse Gas Emissions ("GHG")

March 31, 2008 marked the deadline for the first compliance year with Alberta's Specified Gas Emitters Regulations for GHG reductions. Compliance was required for GHGs emitted from the implementation date of July 1, 2007 to Dec. 31, 2007. Affected firms were required to reduce their emissions by 12 per cent annually from an emissions baseline averaged over 2003 - 2005. For our operations not covered under PPAs, we complied through the delivery to government of purchased emissions offsets, acquired at a competitive cost below the $15 per tonne cap. For Alberta plants having PPA's, we were also responsible for compliance, but the approach was coordinated with PPA Buyers such that a mix of Buyer-supplied offsets, and contributions to the Alberta Technology Fund at $15 per tonne were used. The PPA's contain change-in-law provisions that allow us to recover compliance costs from the PPA customers.

Normal Course Issuer Bid

For the three and six months ended June 30, 2008, we purchased 1,977,500 and 3,886,400 shares, respectively, at an average price of $35.40 and $33.45 per share, respectively. The shares were purchased for an amount higher than their weighted average book value per share ($8.96 and $8.95 per share, respectively) resulting in a reduction of retained earnings of $52 million and $95 million, respectively. Due to the timing of payments to repurchase common shares under NCIB, $53 million was paid in April 2008 that was related to the previous quarter share purchase under the NCIB.

		3 months ended June 30, 2008		**6 months ended June 30, 2008**
Total shares purchased		1,977,500		3,886,400
Average purchase price per share	$	35.40	$	33.45
Total cost	$	70	$	130
Weighted average book value of shares cancelled		18		35
Reduction to retained earnings	**$**	**52**	**$**	**95**

SUBSEQUENT EVENTS

Potential breach of Keephills ash lagoon

On July 26, 2008 we detected a crack in the dyke wall at our Keephills ash lagoon. We immediately notified Alberta Environment and the local authorities, and began taking measures to control and mitigate the effects of any potential breach and release of water from the lagoon. There are no residents in the vicinity and we are restricting access to the area to ensure no one is at risk. We will provide further updates on the situation as they become available.

LS Power and Global Infrastructure Approach TransAlta to Discuss Potential Transaction

On July 18, 2008, we received a non-binding letter from LS Power Equity Partners, an entity associated with Luminus Management LLC, and Global Infrastructure Partners regarding engaging in a dialogue about a possible acquisition of TransAlta for $39 per share in cash. Our Board of Directors will carefully consider the letter and respond in due course.

Contract Negotiations with the International Brotherhood of Electrical Workers ("IBEW")

On July 18, 2008, having been unable to reach an agreement with the IBEW representing our Alberta Thermal and Hydro employees, the government of Alberta approved our application to have the matter referred to a Disputes Inquiry Board. As part of this process, the ability of the IBEW to strike or for us to exercise a lockout is suspended. Contract negotiations will continue during this process with the assistance of a government appointed mediator, and we remain confident that we will be able to reach a settlement with the IBEW.

Debentures

On July 17, 2008, we were advised by the holder of $100 million of debentures held by TransAlta Utilities Corporation (“TAU”), a wholly-owned subsidiary, that they intend to redeem the debentures on July 31, 2008. The debentures were issued at a fixed interest rate of 5.49 per cent, maturing in 2023 and redeemable at the option of the holder in 2008 at a price of $98.45 per $100 of notional. These debentures are included in Current Liabilities.

Carbon Capture

On July 8, 2008, the Alberta government announced its commitment to provide $2 billion in funding for the development of CCS technology. This funding initiative is key to accelerating CCS projects across Alberta and in particular, our chilled ammonia CCS pilot project with Alstom Canada announced in April 2008. We intend to apply for funding support.

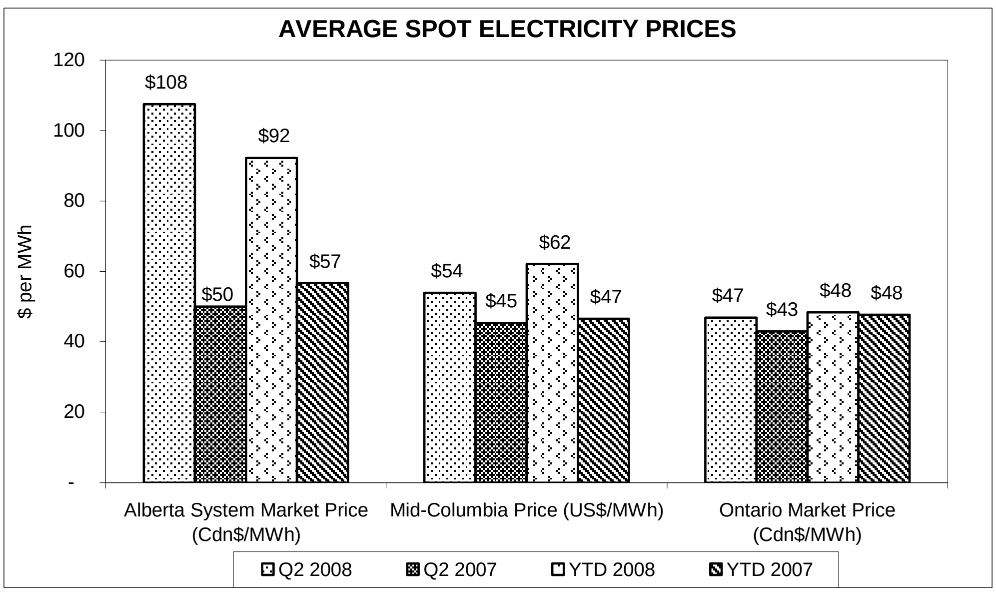
BUSINESS ENVIRONMENT

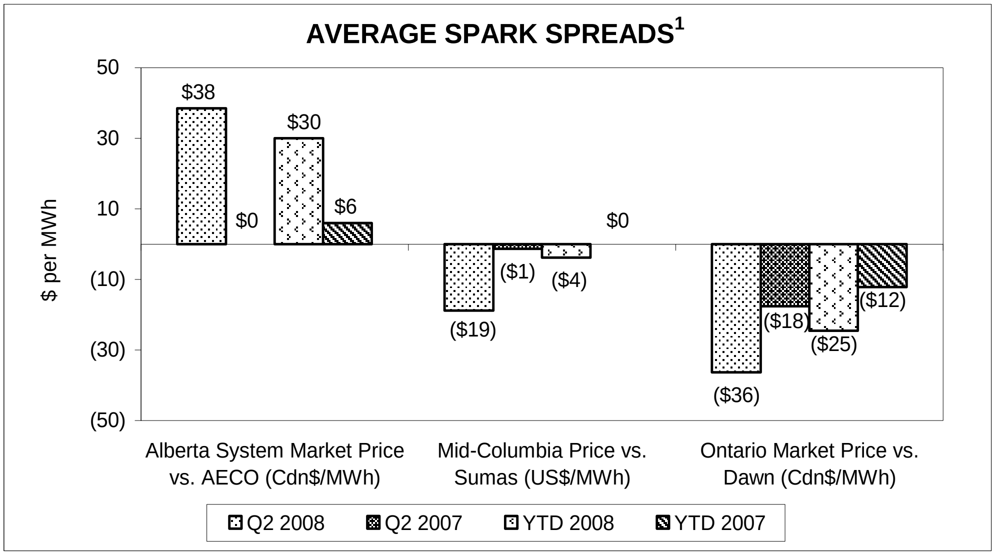
We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Pacific Northwest, and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity in natural gas upon our financial results, refer to our 2007 annual report. The key characteristics of these markets are described below.

Electricity Prices

Please refer to page 30 of the 2007 annual report for a full discussion of the spot electricity market and the impact of electricity prices upon our business. Our strategy is to hedge up to 90 per cent of our merchant production before the delivery year with long term contracts or financial hedges. These sales are staged across a four or five year period, with less production hedged in more distant years. These hedges protect our earnings from some of the risks associated with the spot electricity market.

The average spot electricity prices and spark spreads for the second quarter of 2008 and 2007 in our three main markets are shown in the graphs below.





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

For the second quarter, spot prices in Alberta, the Pacific Northwest and Ontario increased compared to the same period in 2007. Spark spreads increased in Alberta but decreased in the Pacific Northwest and Ontario for the three months ended June 30, 2008 compared to the same period in 2007. Electricity prices and spark spreads were higher in Alberta largely due to coal outages from planned and unplanned outages, from derates caused by transmission system upgrades, and from higher natural gas prices. In the Pacific Northwest, prices were higher due to higher natural gas prices but as a result of strong hydro generation, particularly in May and June, spark spreads were lower compared to the same period in 2007. In Ontario, spot prices were higher, however, spark spreads were lower compared to the same period in 2007, primarily due to lower demand, strong hydro generation, and export restrictions due to transmission limitations.

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, 2007). At June 30, 2008, Generation had 8,384 MW of gross generating capacity[1] in operation (7,977 MW net ownership interest) and 506 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 26 of our 2007 annual report.*

The results of the Generation segment are as follows:

3 months ended June 30		**2008 Total**		**2008 Per installed MWh[1]**		2007 Total		2007 Per installed MWh[1]
Revenues	**$**	**663**	**$**	**36.21**	$	596	$	32.51
Fuel and purchased power		**(332)**		**(18.13)**		(256)		(13.96)
Gross margin		**331**		**18.08**		340		18.55
Operations, maintenance and administration		**139**		**7.59**		130		7.09
Depreciation and amortization		**96**		**5.24**		96		5.24
Taxes, other than income taxes		**5**		**0.27**		5		0.27
Intersegment cost allocation		**8**		**0.44**		7		0.38
Operating expenses		**248**		**13.54**		238		12.98
Operating income	**$**	**83**	**$**	**4.54**	$	102	$	5.57
Installed capacity (GWh)		**18,311**				18,332		
Production (GWh)		**10,652**				11,497		
Availability (%)		**79.3**				83.6		

6 months ended June 30		**2008 Total**		**2008 Per installed MWh[1]**		2007 Total		2007 Per installed MWh[1]
Revenues	**$**	**1,451**	**$**	**39.51**	$	1,254	$	34.21
Fuel and purchased power		**(702)**		**(19.11)**		(547)		(14.92)
Gross margin		**749**		**20.40**		707		19.29
Operations, maintenance and administration		**239**		**6.51**		233		6.36
Depreciation and amortization		**196**		**5.34**		192		5.24
Taxes, other than income taxes		**10**		**0.27**		11		0.30
Intersegment cost allocation		**15**		**0.41**		14		0.38
Operating expenses		**460**		**12.53**		450		12.28
Operating income	**$**	**289**	**$**	**7.87**	$	257	$	7.01
Installed capacity (GWh)		**36,729**				36,654		
Production (GWh)		**23,878**				24,194		
Availability (%)		**85.5**				85.9		

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

Production and gross margins

Generation's production volumes, electricity and steam production revenues and fuel and purchased power costs based on geographical regions are presented below:

3 months ended June 30, 2008	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & Purchased Power**	**Gross Margin**	**Revenue per installed MWh[1]**	**Fuel & Purchased Power per installed MWh[1]**	**Gross Margin per installed MWh[1]**
Western Canada	**7,925**	**11,406**	**$ 335**	**$ 138**	**$ 197**	**$ 29.37**	**$ 12.10**	**$ 17.27**
Eastern Canada	**726**	**1,789**	**131**	**98**	**33**	**73.23**	**54.78**	**18.45**
International	**2,001**	**5,116**	**197**	**96**	**101**	**38.51**	**18.76**	**19.75**
	10,652	**18,311**	**$ 663**	**$ 332**	**$ 331**	**$ 36.21**	**$ 18.13**	**$ 18.08**

3 months ended June 30, 2007	Production (GWh)	Installed (GWh)	Revenue	Fuel & Purchased Power	Gross Margin	Revenue per installed MWh[1]	Fuel & Purchased Power per installed MWh[1]	Gross Margin per installed MWh[1]
Western Canada	8,012	11,320	$ 306	$ 99	$ 207	$ 27.03	$ 8.75	$ 18.28
Eastern Canada	824	1,793	106	74	32	59.12	41.27	17.85
International	2,661	5,219	184	83	101	35.26	15.90	19.36
	11,497	18,332	$ 596	$ 256	$ 340	$ 32.51	$ 13.96	$ 18.55

6 months ended June 30, 2008	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & Purchased Power**	**Gross Margin**	**Revenue per installed MWh[1]**	**Fuel & Purchased Power per installed MWh[1]**	**Gross Margin per installed MWh[1]**
Western Canada	**16,683**	**22,816**	**$ 695**	**$ 259**	**$ 436**	**$ 30.46**	**$ 11.35**	**$ 19.11**
Eastern Canada	**1,615**	**3,578**	**264**	**189**	**75**	**73.78**	**52.82**	**20.96**
International	**5,580**	**10,335**	**492**	**254**	**238**	**47.61**	**24.58**	**23.03**
	23,878	**36,729**	**$ 1,451**	**$ 702**	**$ 749**	**$ 39.51**	**$ 19.11**	**$ 20.40**

6 months ended June 30, 2007	Production (GWh)	Installed (GWh)	Revenue	Fuel & Purchased Power	Gross Margin	Revenue per installed MWh[1]	Fuel & Purchased Power per installed MWh[1]	Gross Margin per installed MWh[1]
Western Canada	16,829	22,629	$ 654	$ 217	$ 437	$ 28.90	$ 9.59	$ 19.31
Eastern Canada	1,809	3,587	234	159	75	65.24	44.33	20.91
International	5,556	10,438	366	171	195	35.06	16.38	18.68
	24,194	36,654	$ 1,254	$ 547	$ 707	$ 34.21	$ 14.92	$ 19.29

Western Canada

Our Western Canada assets consist of coal, natural gas-fired, and hydro facilities and wind farms. Refer to page 39 of our 2007 annual report for further details on our Western operations.

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

The change in production for the three and six months ended June 30, 2008 is reconciled below:

	3 months ended June 30	6 months ended June 30
Production, 2007	8,012	16,829
Lower planned outages at Alberta Thermal	151	242
Increased merchant production primarily resulting from the uprate at our Sundance facility	117	291
Higher unplanned outages at Alberta Thermal	(320)	(490)
Higher planned outages at Genesee 3	(144)	(144)
Higher / (lower) customer demand	60	(36)
Other	49	(9)
Production, 2008	**7,925**	**16,683**

The change in gross margin for the three and six months ended June 30, 2008 is reconciled below:

	3 months ended June 30	6 months ended June 30
Gross margin, 2007	207	437
Favourable pricing	21	27
Lower planned outages at Alberta Thermal	5	8
Higher unplanned outages at Alberta Thermal	(15)	(27)
Increased merchant production primarily resulting from the uprate at our Sundance facility	6	16
Mark-to-market movements	-	(4)
Higher planned outages at Genesee 3	(6)	(6)
Higher coal costs	(5)	(5)
Favourable commercial settlements in 2007	(12)	(12)
Other	(4)	2
Gross margin, 2008	**197**	**436**

Eastern Canada

Our Eastern Canada assets consist of natural gas-fired facilities and a wind farm under development. Refer to page 39 of our 2007 annual report for further details on our Eastern operations.

Production for the three and six months ended June 30, 2008 decreased 98 gigawatt hours (“GWh”) and 194 GWh, respectively, primarily due to lower market heat rates at Sarnia.

For the three and six months ended June 30, 2008, gross margins were comparable to the same periods in 2007.

International

Our International assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States and natural gas assets in Australia. Refer to page 39 of our 2007 annual report for further details on our International operations.

For the three months ended June 30, 2008, production decreased 660 GWh due to Centralia equipment modifications (794 GWh) and economic dispatching (386 GWh) at Centralia Thermal, partially offset by lower unplanned outages at Centralia Thermal (545 GWh). For the six months ended June 30, 2008 production increased slightly compared to the same period in 2007, due to lower derates at Centralia Thermal resulting from test burns of Powder River Basin (“PRB”) coal in 2007, partially offset by higher planned outages and lower production in 2008 at Centralia Thermal.

The change in gross margin for the three and six months ended June 30, 2008 is reconciled below:

	3 months ended June 30	6 months ended June 30
Gross margin, 2007	101	195
Decreased production at Centralia Thermal	(27)	(1)
Favourable pricing	30	44
Mark-to-market movements	9	27
Unfavorable foreign exchange	(7)	(28)
Other	(5)	1
Gross margin, 2008	**101**	**238**

Operations, maintenance and administration expense

For the three months ended June 30, 2008, OM&A expense increased compared to the same periods in 2007 primarily due to an increase in planned outages at Genesee 3 and Centralia Thermal. OM&A remained comparable for the six months ended June 30, 2008 with the same period in 2007, as inflation has been offset through productivity initiatives.

Depreciation expense

Depreciation expense remained comparable for the three months ended June 30, 2008 compared to 2007. For the six months ended June 30, 2008, depreciation expense increased due to the early retirement of certain components as a result of equipment modifications made at Centralia Thermal.

COMMERCIAL OPERATIONS & DEVELOPMENT ("COD"): *derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving gross margins while remaining within value at risk ("VAR") limits is a key measure of COD's trading activities.*

COD is responsible for the management of commercial activities for our current generating assets. COD also manages available generating capacity as well as the fuel and transmission needs of the Generation business by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas, coal, and transmission capacity. Further, COD is responsible for developing or acquiring new cogeneration, wind, geothermal, and hydro generating assets and recommending portfolio optimization opportunities. The results of all of these activities are included in the Generation segment.

For a more in-depth discussion of the accounting treatment of our Energy Trading activities, refer to page 40 of our 2007 annual report.

The results of the COD segment are as follows:

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Gross margin	**$ 45**	$ 16	**$ 60**	$ 27
Operations, maintenance and administration	**10**	8	**20**	17
Depreciation and amortization	**1**	1	**1**	1
Intersegment cost allocation	**(8)**	(7)	**(15)**	(14)
Operating expenses	**3**	2	**6**	4
Operating income	**$ 42**	$ 14	**$ 54**	$ 23

For the three and six months ended June 30, 2008, gross margins increased relative to the same period in 2007 due to increased trading volumes and from the successful execution of trading strategies involving regional power demand and price differentials.

OM&A costs for the three and six months ended June 30, 2008 increased due to increased staffing to support business activities.

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

NET INTEREST EXPENSE

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Interest on long-term debt	**$ 36**	$ 37	**$ 68**	$ 76
Interest on short-term debt	**6**	6	**16**	13
Interest income	**(4)**	(6)	**(9)**	(14)
Capitalized interest	**(3)**	-	**(7)**	(1)
Net interest expense	**$ 35**	$ 37	**$ 68**	$ 74

For the three and six months ended June 30, 2008, net interest expense decreased compared to the same periods in 2007, as shown below:

	3 months ended June 30	6 months ended June 30
Net interest expense, 2007	37	74
Lower long-term debt levels	-	(4)
Higher short-term debt balances	-	3
Lower interest income from cash deposits	2	5
Higher capitalized interest	(3)	(6)
Change in foreign exchange rates	(1)	(4)
Net interest expense, 2008	**35**	**68**

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests in the three and six months ended June 30, 2008 were comparable to the same periods in 2007.

EQUITY LOSS

As required under Accounting Guideline 15, *Consolidation of Variable Interest Entities*, of the Canadian Institute of Chartered Accountants (“CICA”), our Mexican operations are accounted for as equity subsidiaries. On Feb. 20, 2008, we entered into an agreement to sell our Mexican operations to InterGen. The transaction is subject to regulatory approvals in Mexico and transaction closing conditions, and is expected to close before the end of the third quarter of 2008. The table below summarizes key information from these operations.

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Availability (%)	**98.9**	94.8	**98.6**	95.8
Production (GWh)	**925**	861	**1,785**	1,440
Equity loss	**$ -**	$ (2)	**$ (97)**	$ (11)
Operating cash flow	**$ 4**	$ (4)	**$ 3**	$ 14
Interest expense	**$ 4**	$ 6	**$ 9**	$ 16

	June 30, 2008	Dec. 31, 2007
Total assets	**$ 456**	$ 451
Total liabilities	**$ 374**	$ 369

For the three months ended June 30, 2008 availability increased due to lower unplanned outages at Campeche. For the six months ended June 30, 2008, availability increased due to lower planned and unplanned outages at Chihuahua and lower unplanned outages at Campeche.

For the three and six months ended June 30, 2008 production increased due to lower unplanned outages at Campeche and lower planned outages at Chihuahua combined with increased customer demand at both facilities.

For the three months ended June 30, 2008, equity loss was nil. For the six months ended June 30, 2008, equity loss increased due to the writedown on the anticipated sale of our Mexican investment.

INCOME TAXES

	3 months ended June 30		6 months ended June 30, 2008	
	2008	2007	**2008**	2007
Earnings before income taxes	**$ 51**	$ 63	**$ 98**	$ 139
Equity loss	**-**	(2)	**(97)**	(11)
Earnings before income taxes and excluding equity loss	**$ 51**	$ 65	**$ 195**	$ 150
Income tax prior to adjustment for rate change	**4**	14	**18**	34
Change in tax rate related to prior periods	**-**	(8)	**-**	(8)
Income tax expense per financial statements	**4**	6	**18**	26
Income tax impact of writedown of equity investment	**-**	-	**28**	-
Income tax expense prior to writedown of equity investment	**4**	6	**46**	26
Net income prior to writedown of equity investment	**$ 47**	$ 60	**$ 177**	$ 125
Effective tax rate (%)[1]	**8**	8	**24**	17

Tax expense decreased for the three months ended June 30, 2008 due to a decrease in pre-tax earnings.

The underlying tax expense increased for the six months ended June 30, 2008 compared to the same period in 2007 due to an increase in pre-tax earnings. The tax recovery on the writedown of our Mexican investment more than offset this increase in pre-tax earnings.

1 To present comparable reconciliations, prior years' effective tax rate analysis were reclassified and calculated on earnings before income tax and excluding equity loss.

FINANCIAL POSITION

The following chart outlines significant changes in the consolidated balance sheet from Dec. 31, 2007 to June 30, 2008:

	Increase/ (Decrease)	Explanation of change
Prepaid expenses	12	Timing of insurance premiums and other prepaids
Income taxes receivable	14	Current tax provision
Inventory	38	Higher inventory balances as a result of lower production
Restricted cash	(240)	Return of funds and decrease in exchange rates
Investments	146	Loan to equity investment of $245 million partially offset by net loss and writedown of investments
Property, plant, and equipment, net	289	Capital additions partially offset by the strengthening of the Canadian dollar compared to the U.S. dollar and depreciation expense
Assets held for sale, net	(29)	Assets previously held for sale have been reclassified to property, plant, and equipment
Intangible assets	(12)	Amortization expense and the strengthening of the Canadian dollar
Short-term debt	(201)	Net decrease in short-term debt
Accounts payable and accrued liabilities	66	Timing of operational payments
Recourse long-term debt (including current portion)	400	Issuance of long-term debt of U.S.$500 million partially offset by debt repayments
Risk management liabilities (current and long-term)	679	Price movements
Net future income tax liabilities (including current portions)	(219)	Tax effect on the increase in net risk management liabilities
Shareholders' equity	(512)	Shares redeemed under the NCIB, dividends declared, and movements in AOCI partially offset by net earnings

FINANCIAL INSTRUMENTS

Refer to *Note 7* on page 85 of the 2007 annual report and the second quarter notes to the financial statements for details on Financial Instruments. During the current quarter the change in net liability position of financial instruments is a result of changes in future prices on contracts in our Generation segment. Refer to the 'Risk Management' section in the MD&A in the annual report outlining our risks and how we manage them. Our risk management profile and practices have not changed materiality from Dec. 31, 2007.

STATEMENTS OF CASH FLOWS

3 months ended June 30		2008		2007	Explanation of change
Cash and cash equivalents, beginning of period	**$**	**58**	$	79	
Provided by (used in):					
Operating activities		**171**		168	In 2008, cash inflows resulted from cash earnings of $171 million. In 2007, cash inflows resulted from cash earnings of $172 million partially offset by cash used in working capital of $4 million.
Investing activities		**(221)**		(99)	In 2008 cash outflows were primarily due to additions to property, plant and equipment of $239 million and the loan to equity investment of $245 million partially offset by return of restricted cash of $242 million. In 2007, cash outflows were primarily due to additions of property, plant and equipment of $140 million partially offset by proceeds on sale of assets of $23 million and by return of restricted cash of $28 million.
Financing activities		**42**		(101)	In 2008, cash inflows were due to the issuance of long-term debt of $502 million, partially offset by the reduction of short-term debt of $137 million, repayment of long-term debt of $126 million, funds paid to repurchase common shares under NCIB of $119 million, and dividends paid on common shares of $54 million. In 2007, cash outflows were due to dividends on common shares of $51 million, repayment of long-term debt of $11 million, reduction of short-term debt of $25 million, and distributions to non-controlling interests of $20 million.
Translation of foreign currency cash		**-**		6	
Cash and cash equivalents, end of period	**$**	**50**	$	53	

6 months ended June 30		2008		2007	Explanation of change
Cash and cash equivalents, beginning of year	$	**51**	$	66	
Provided by (used in):					
Operating activities		**408**		499	In 2008, cash inflows were due to cash earnings of $404 million. In 2007, cash inflows were due to cash earnings of $370 million and favourable change in working capital of $129 million due to collection of 2006 revenues in 2007.
Investing activities		**(334)**		(154)	In 2008, cash outflows were primarily due to additions of property, plant and equipment of $389 million and the loan to equity investment of $245 million, partially offset by return of restricted cash of $245 million and proceeds on sale of assets of $21 million. In 2007, cash outflows were primarily due to additions of property, plant, and equipment of $194 million, partially offset by proceeds on sale of property, plant and equipment of $23 milion and reduction in restricted cash of $37 million.
Financing activities		**(78)**		(364)	In 2008, cash outflows were due to a reduction in short-term debt of $201 million, repayment of long-term debt of $130 million, funds to repurchase common shares under the NCIB of $126 million, and dividends paid on common shares of $105 million, partially offset by $502 million on the issuance of long-term debt. In 2007, cash outflows were due to dividends on common shares of $105 million, redemption of preferred securities of $175 million, reduction of long-term debt of $23 million, reduction of short-term debt of $32 million, and distributions paid to non-controlling interests of $41 million.
Translation of foreign currency cash		**3**		6	
Cash and cash equivalents, end of period	$	**50**	$	53	

LIQUIDITY AND CAPITAL RESOURCES

Details on our liquidity needs and capital resources can be found on page 50 of our 2007 annual report.

We have a total of $2.2 billion of committed and uncommitted credit facilities of which $0.9 billion is not drawn and is available as of June 30, 2008, subject to customary borrowing conditions. At June 30, 2008, credit utilized under these facilities is $1.2 billion which is comprised of short-term debt of $450 million less cash on hand of $50 million, and of letters of credit of $828 million.

Our ability to generate adequate cash flow from operations in the short-term and the long-term to maintain financial capacity and flexibility and to provide for planned growth remains substantially unchanged since Dec. 31, 2007. In the first quarter of 2008 we received $116 million worth of PPA revenue from 2007 due to timing of contractually scheduled payments. Consequently, the effect of the timing of these payments is that we will receive 13 months of revenue in 2008.

On July 30, 2008, we had approximately 198 million common shares outstanding.

At June 30, 2008, we had 1.8 million outstanding employee stock options with a weighted average exercise price of $25.90. For the three months ended June 30, 2008, 0.1 million options with a weighted average exercise price of $20.33 were exercised resulting in 0.1 million shares issued.

On Feb. 1, 2008, 1 million stock options were granted at an exercise price of $31.97 on the TSX for Canadian employees and U.S.$31.83 on the New York Stock Exchange ("NYSE") for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire after 10 years.

Guarantee contracts

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, 2008, we had issued letters of credit totaling $828 million compared to $550 million at Dec. 31, 2007. This increase in letters of credit is due primarily to higher forward electricity prices in the Pacific Northwest. These letters of credit secure certain amounts included in our balance sheet under "Risk Management Liabilities" and "Asset Retirement Obligations".

CLIMATE CHANGE AND THE ENVIRONMENT

In the second quarter of 2008, there have been no significant changes in environmental legislation in Canada affecting our operations. The Canadian Federal Government continues to develop its GHG regulations under the Canadian Environmental Protection Act, with a stated objective of announcing draft regulations in the fall of 2008. Industry has been engaged in consultations with the government on the details of the regulatory design. These regulations would come into effect in 2010.

The Alberta climate change program under the Specified Gas Emitters Act remains in place, requiring a 12 per cent emissions intensity reduction from a 2003 - 2005 average baseline. We have measures in place to meet the anticipated reduction targets for 2008 and 2009, and continue to examine compliance options, including additions to our offsets portfolio to hedge our compliance risk beyond that period.

Discussions are occurring between the Alberta and the Federal Governments regarding harmonization of climate change regulations between the two jurisdictions.

On July 8, 2008, the Alberta Government announced a major $2 billion initiative to support the early deployment of carbon capture and storage projects in the province. The allocation of these resources is expected to be made in the late fall this year. We plan to submit our previously announced chilled ammonia CCS pilot project to be developed in partnership with Alstom Canada for consideration.

We are continuing with detailed technology testing and engineering design in preparation for installing mercury control equipment at our Alberta Thermal operations by 2010 in order to meet the province's 70 per cent reduction objectives. We are on track to meet that deadline.

In the United States, Washington State is developing the conceptual design for a cap and trade mechanism to manage greenhouse gases. The preliminary design is to be drafted by December 2008. In parallel, Washington State is engaged with other western states in the Western Climate Initiative to examine a regional cap and trade system for carbon. At this point there are no indications as to how these initiatives will impact our fossil-fired assets in Washington.

OUTLOOK

Business Environment

Power Prices

For the remainder of 2008, power prices are expected to remain strong due primarily to high natural gas prices in all regions. In the Pacific Northwest, hydro generation is expected to decrease as the seasonal runoff abates. Prices in Alberta are expected to be influenced primarily by unit availability and weather in addition to natural gas 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. Refer to pages 55 through 62 of our annual report for a further discussion of our key risks and our risk management activities and strategies.

Environmental Legislation

In the balance of 2008, we anticipate additional regulatory clarity on future GHG requirements. While the Alberta regulations are clear until the end of 2009, it is uncertain how the proposed federal regulations will affect Alberta firms from 2010 onward. The development of the federal regulations scheduled for the fall of 2008 will prompt discussions between the Federal Government and the provinces about whose rules are to be applied and who will administer them. Similarly in Washington State, we expect to see the State's proposals by December this year as to the market-based mechanism design for regulating GHG in Washington State and possibly surrounding states in the region.

Additionally, this year we expect to see the development on Canadian federal plans for air pollutant reductions, initially at the framework level of targets and compliance mechanisms. We intend to be an active participant in consultations leading up to the release of those targets.

Operations

Production, Availability, and Capacity

Generating capacity is expected to increase due to the completion of Kent Hills late in 2008. Production and availability are expected to increase in the third and fourth quarters compared to the second quarter, as a result of lower planned maintenance and lower unplanned outages.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to increased overburden removal, inflation, and increases in diesel and commodity prices. Seasonal variations in coal mining at our Alberta mines are minimized through the application of standard costing which was adjusted by $5 million in the second quarter as a result of higher diesel prices. This increase in diesel prices is also anticipated to increase coal costs for the entire year by up to $15 million. We anticipate recovering this increase in the cost of diesel through the indices incorporated in the Alberta PPAs and recording a corresponding increase in 2009 PPA revenues. However, as these indices are adjusted during a three month period, the increase in PPA revenues in 2009 may or may not be directly linked to the increase of costs for the entire period of 2008.

Fuel at Centralia Thermal is purchased from external suppliers. These contract prices are expected to increase slightly in 2008 from those seen in the first and second quarters due to contract and commodity escalations.

Our gas-fired facilities have minimal exposure to market fluctuations in energy commodity prices. Exposure to gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term gas purchase contracts. 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 to date as gas will be purchased coincident with spot pricing.

Operations, Maintenance, and Administration Costs

OM&A costs per megawatt hour ("MWh") of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per MWh are expected to be slightly higher in the third quarter primarily due to higher planned maintenance at Alberta Thermal, partially offset by lower planned maintenance across the remainder of the fleet. OM&A costs per MWh of installed capacity are expected to decrease in the fourth quarter mainly due to lower planned maintenance activities.

Energy Trading

Earnings from our COD 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 current forecast, for 2008, is for proprietary trading to contribute between $60 million and $80 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 2008 is expected to be higher mainly due to higher debt balances and lower interest income. However, changes in interest rates and 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 may increase, which can cause the need for additional liquidity. To mitigate this liquidity risk, we maintain and monitor $2.2 billion in committed and uncommitted credit facilities and monitor exposures to determine any expected liquidity requirements.

In the third quarter of 2008 we will receive three payments under the PPAs compared to two payments received during the same period in 2007.

Normal Course Issuer Bid

The NCIB program was renewed on May 6, 2008 and will continue until May 5, 2009. Purchases will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

Projects and Growth

Our capital expenditures and major projects are comprised of spending on sustaining our current operations and for growth activities.

Five significant growth capital projects are currently in progress: Keephills 3, Kent Hills, Blue Trail, Sundance Unit 5 uprate, and Summerview.

A summary of each of these projects is outlined below:

Project	Total Spend (millions)	Expected 2008 spend (millions)	Expected Completion Date	Details
Keephills 3	$815	$320 - 330	Q1 2011	A 450 MW (225 MW net of ownership) coal-fired supercritical plant and associated mine capital in a partnership with EPCOR
Kent Hills	$170	$135 - 145	Q4 2008	96 MW wind farm in New Brunswick to operate under a power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation
Blue Trail	$115	$20 - 25	Q4 2009	A 66 MW merchant wind farm in southern Alberta
Sundance Unit 5 uprate	$75	$15 - 20	Q4 2009	A 53 MW efficiency uprate at our Sundance facility
Summerview	$123	$20 - 30	Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Total growth	**$1,298**	**$510 - 550**		

Sustaining Expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2008, our estimate for total sustaining capital expenditures, excluding our Mexico operations, is between $425 million and $460 million, allocated among:

- $145 - $155 million for routine capital,
- $100 - $110 million for mining equipment,
- $70 - $75 million for Centralia modifications, and
- $110 - $120 million on planned maintenance, with approximately 2,400 – 2,525 GWh lost.

Financing

Financing for these expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity.

RELATED PARTY TRANSACTIONS

On Dec.16, 2006, TAU, a wholly-owned subsidiary of TransAlta, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership with a wholly-owned subsidiary of TransAlta, TransAlta Energy Corporation ("TEC") and EPCOR. TAU will supply coal until the earlier of the Keephills 3 facility permanently ceasing operations or the termination of the agreement by TAU and the partners of the joint venture. As at June 30, 2008, TAU had received $22 million from Keephills 3 Limited Partnership, a wholly-owned subsidiary, as a pre-payment of coal to be delivered under the contract. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011.

In August 2006, we entered into an agreement with CE Generation, LLC ("CE Gen"), a Corporation jointly controlled by us and MidAmerican Energy Holdings Company ("MidAmerican"), a subsidiary of Berkshire Hathaway, whereby we buy 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, one of our subsidiaries, TransAlta Cogeneration, L.P. ("TA Cogen") entered into various transportation swap transactions with 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 the Sheerness thermal plant, which is operated by Canadian Utilities Limited. 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. We entered into an offsetting contract with an external third party, therefore we have no risk other than counterparty risk.

CURRENT ACCOUNTING CHANGES

Financial Instruments – Disclosures and Presentation

On Dec. 1, 2006, the CICA issued two new accounting standards: Handbook Section 3862, *Financial Instruments – Disclosures* and Handbook Section 3863, *Financial Instruments – Presentation*. These new standards were effective on Jan. 1, 2008.

The new CICA Handbook Sections 3862 and 3863 replace Handbook Section 3861, *Financial Instruments — Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged presentation requirements. These new sections place increased emphasis on disclosures made about the nature and extent of risks arising from financial instruments and how the entity manages those risks. Refer to the notes to the financial statements.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

In 2005, the Accounting Standards Board ("AcSB") announced that accounting standards in Canada are to converge with IFRS. On Feb. 13, 2008, the AcSB confirmed that the use of IFRS will be required by Jan. 1, 2011 with appropriate comparative data from the prior year. Under IFRS, 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 that must be addressed.

On Dec. 31, 2007, the United States Securities and Exchange Commission approved rule amendments that will allow foreign private issuers to issue financial statements without reconciliation to U.S. GAAP, if they are prepared using the English language version of IFRS as issued by the International Accounting Standards Board.

We have developed a plan to transition to IFRS by January 2011. An initial investigation has been conducted to assess the implementation impacts including changes to accounting policies and processes, information systems, and business management.

A team has been established to further analyze the key areas identified in the plan and is working in conjunction with Information

Technology and Internal Control resources to determine process and system changes along with appropriate financial reporting controls.

The full impact of adopting IFRS on our future financial position and future results cannot be reasonably determined at this time. We are carefully evaluating the transitional options available under IFRS at the adoption date as well as the most appropriate long-term accounting policies.

Our preliminary view is that there are many similarities between Canadian GAAP and IFRS and that the major differences for us will likely arise in respect of property, plant, and equipment and the impairment of long-lived assets with potential impacts from expected revisions to existing IFRS standards in accounting for joint ventures and post-retirement benefits.

A steering committee has been established to monitor the progress and critical decisions in the transition to IFRS. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources and Operations. Quarterly updates are provided to the Audit and Risk Committee.

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 our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

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

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

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Gross margin	**$ 376**	$ 356	**$ 809**	$ 734
Operating expenses	**(283)**	(265)	**(527)**	(505)
Operating income	**93**	91	**282**	229
Foreign exchange gain (loss)	**-**	5	**(1)**	5
Gain on sale of equipment	**-**	12	**5**	12
Net interest expense	**(35)**	(37)	**(68)**	(74)
Equity loss	**-**	(2)	**(97)**	(11)
Earnings before non-controlling interests and income taxes	**58**	69	**121**	161
Non-controlling interests	**7**	6	**23**	22
Earnings before income taxes	**51**	63	**98**	139
Income tax expense	**4**	6	**18**	26
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113

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.

In calculating comparable earnings for 2008, we have excluded the writedown of our Mexican investment as the sale of such operations is a one time adjustment.

The change in life of certain component parts at Centralia Thermal was excluded as it is related to the cessation of mining activities at the Centralia coal mine and conversion to consuming solely third party supplied coal. Additionally, we excluded the gains recorded on the sale of assets in 2007 and 2008 at the previously operated Centralia coal mine as we do not normally dispose of large quantities of fixed assets. We excluded the impact of the tax rate changes as they do not related to current period earnings.

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Earnings on a comparable basis	**$ 49**	$ 42	**$ 148**	$ 98
Sale of assets at Centralia, net of tax	**-**	8	**4**	8
Change in life of Centralia parts, net of tax	**(2)**	-	**(7)**	-
Recovery from resolution of uncertain tax positions	**-**	-	**-**	-
Investments writedown, net of tax	**-**	-	**(65)**	-
Tax rate change	**-**	7	**-**	7
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113
Weighted average common shares outstanding in the period	**199**	203	**200**	203
Earnings on a comparable basis per share	**$ 0.25**	$ 0.20	**$ 0.74**	$ 0.48

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.

Sustaining capital expenditures for the three months ended June 30, 2008, represents total capital expenditures per the statement of cash flow less $125 million we have invested in growth projects. For the same period in 2007, we invested $60 million in growth projects. For the six months ended June 30, 2008 and 2007, we invested $192 and $73 million, respectively, 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	
	2008	2007	**2008**	2007
Cash flow from operating activities	**$ 171**	$ 168	**$ 408**	$ 499
Add (Deduct):				
Sustaining capital expenditures	**(114)**	(80)	**(197)**	(121)
Dividends on common shares	**(54)**	(51)	**(105)**	(105)
Distribution to subsidiaries' non-controlling interest	**(27)**	(20)	**(44)**	(41)
Non-recourse debt repayments	**(2)**	(37)	**(2)**	(46)
Timing of contractualy scheduled payments	**-**	-	**(116)**	(185)
Centralia closure costs	**-**	1	**-**	24
Cash flows from equity investments	**4**	10	**3**	8
Free cash flow	**$ (22)**	$ (9)	**$ (53)**	$ 33

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

SELECTED QUARTERLY INFORMATION
(in millions of Canadian dollars except per share amounts)

	Q3 2007	Q4 2007	Q1 2008	Q2 2008
Revenue	**$ 712**	**$ 783**	**$ 803**	**$ 708**
Net earnings	**66**	**129**	**33**	**47**
Basic earnings per common share	**0.33**	**0.64**	**0.17**	**0.24**
Diluted earnings per common share	**0.33**	**0.64**	**0.17**	**0.24**

	Q3 2006	Q4 2006	Q1 2007	Q2 2007
			(restated)	
Revenue	$ 656	$ 752	$ 669	$ 612
Net earnings (loss)	35	(146)	56	57
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

ADJUSTMENT TO REPORTED FIRST QUARTER RESULTS FOR 2007

The net earnings for the three months ended March 31, 2007 were adjusted 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 for the first quarter net earnings were 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 was increased by a corresponding after-tax amount of $9.8 million. The resulting earnings per share for the first quarter of 2007 was $0.28 per share, compared to the originally reported $0.33 per share, a further reduction of $0.05 per share.

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934 (“Exchange Act”), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2008, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD-LOOKING STATEMENTS

This MD&A 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 and assumptions discussed in this MD&A under the headings ‘Outlook’ and ‘Business Environment’ and in the MD&A in our annual report for the year ended Dec. 31, 2007 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	**2008**	2007	**2008**	2007
Revenues	**$ 708**	$ 612	**$ 1,511**	$ 1,281
Fuel and purchased power	**(332)**	(256)	**(702)**	(547)
Gross margin	**376**	356	**809**	734
Operations, maintenance, and administration	**178**	160	**313**	295
Depreciation and amortization *(Note 19)*	**100**	100	**204**	199
Taxes, other than income taxes	**5**	5	**10**	11
Operating expenses	**283**	265	**527**	505
Operating income	**93**	91	**282**	229
Foreign exchange gain (loss)	**-**	5	**(1)**	5
Gain on sale of equipment *(Note 8)*	**-**	12	**5**	12
Net interest expense *(Note 9)*	**(35)**	(37)	**(68)**	(74)
Equity loss *(Note 7)*	**-**	(2)	**(97)**	(11)
Earnings before non-controlling interests and income taxes	**58**	69	**121**	161
Non-controlling interests	**7**	6	**23**	22
Earnings before income taxes	**51**	63	**98**	139
Income tax expense	**4**	6	**18**	26
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113
Retained earnings				
Opening balance	**699**	715	**763**	710
Common share dividends	**(54)**	(50)	**(108)**	(101)
Shares cancelled under NCIB *(Note 12)*	**(52)**	-	**(95)**	-
Closing balance	**$ 640**	$ 722	**$ 640**	$ 722
Weighted average number of common shares outstanding in the period	**199**	203	**200**	203
Net earnings per share, basic and diluted	**$ 0.24**	$ 0.28	**$ 0.40**	$ 0.56

See accompanying notes.

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

Unaudited		**June 30, 2008**		Dec. 31, 2007
ASSETS				
Current assets				
Cash and cash equivalents *(Note 2)*	**$**	**50**	$	51
Accounts receivable *(Notes 2 and 17)*		**540**		546
Prepaid expenses		**21**		9
Risk management assets *(Notes 1, 2, 3 and 4)*		**180**		93
Future income tax assets		**136**		40
Income taxes receivable		**63**		49
Inventory *(Note 5)*		**68**		30
		1,058		818
Restricted cash *(Notes 2 and 6)*		**2**		242
Investments *(Note 7)*		**271**		125
Long-term receivables *(Note 10)*		**2**		6
Property, plant, and equipment				
Cost		**9,059**		8,593
Accumulated depreciation		**(3,653)**		(3,476)
		5,406		5,117
Assets held for sale, net *(Note 8)*		**-**		29
Goodwill *(Note 19)*		**127**		125
Intangible assets		**197**		209
Future income tax assets		**374**		303
Risk management assets *(Notes 1, 2, 3 and 4)*		**39**		122
Other assets		**78**		83
Total assets	**$**	**7,554**	$	7,179
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Short-term debt *(Note 2)*	**$**	**450**	$	651
Accounts payable and accrued liabilities *(Note 2)*		**539**		473
Risk management liabilities *(Notes 1, 2, 3 and 4)*		**509**		105
Income taxes payable		**8**		17
Future income tax liabilities		**12**		12
Dividends payable		**52**		49
Current portion of long-term debt - recourse *(Notes 2, 9 and 22)*		**105**		122
Current portion of long-term debt - non-recourse *(Notes 2 and 9)*		**29**		32
Current portion of asset retirement obligations *(Note 10)*		**44**		43
		1,748		1,504
Long-term debt - recourse *(Notes 2 and 9)*		**1,913**		1,496
Long-term debt - non-recourse *(Notes 2 and 9)*		**211**		209
Asset retirement obligation *(Note 10)*		**237**		233
Deferred credits and other long-term liabilities		**113**		101
Future income tax liabilities		**585**		637
Risk management liabilities *(Notes 1, 2, 3 and 4)*		**475**		204
Non-controlling interests		**485**		496
Common shareholders' equity				
Common shares *(Notes 11 and 12)*		**1,760**		1,781
Retained earnings *(Note 12)*		**640**		763
Accumulated other comprehensive loss *(Notes 1 and 12)*		**(613)**		(245)
Total shareholders' equity		**1,787**		2,299
Total liabilities and shareholders' equity	**$**	**7,554**	$	7,179

Contingencies *(Notes 15 and 17)*
Commitments *(Notes 3, 15 and 16)*
Subsequent events *(Note 22)*

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2008**	2007	**2008**	2007
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113
Other comprehensive loss				
(Losses) gains on translating net assets of self-sustaining foreign operations	**(5)**	(88)	**62**	(104)
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations	**5**	108	**(78)**	123
Tax expense (recovery)	**3**	20	**(8)**	21
	2	88	**(70)**	102
Losses on translation of self-sustaining foreign operations	**(3)**	-	**(8)**	(2)
Losses on derivatives designated as cash flow hedges	**(362)**	(119)	**(591)**	(246)
Tax recovery	**(123)**	(38)	**(203)**	(78)
Losses on derivatives designated as cash flow hedges	**(239)**	(81)	**(388)**	(168)
Derivatives designated as cash flow hedges in prior periods transferred to balance sheet in the current period	**2**	-	**6**	-
Derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period	**19**	(5)	**36**	3
Tax expense (recovery)	**7**	(1)	**14**	1
	14	(4)	**28**	2
Other comprehensive loss	**(228)**	(85)	**(368)**	(168)
Comprehensive loss	**$ (181)**	$ (28)	**$ (288)**	$ (55)

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2008**	2007	**2008**	2007
Operating activities				
Net earnings	**$ 47**	$ 57	**$ 80**	$ 113
Depreciation and amortization *(Note 19)*	**104**	100	**211**	200
Gain on sale of equipment *(Note 8)*	**-**	(12)	**(5)**	(12)
Non-controlling interests	**7**	6	**23**	22
Asset retirement obligation accretion *(Note 10)*	**6**	6	**11**	12
Asset retirement costs settled *(Note 10)*	**(8)**	(5)	**(12)**	(8)
Future income taxes	**5**	5	**(11)**	(2)
Unrealized losses from risk management activities	**14**	21	**15**	40
Foreign exchange (gain) loss	**-**	(5)	**1**	(5)
Equity loss *(Note 7)*	**-**	2	**97**	11
Other non-cash items	**(4)**	(3)	**(6)**	(1)
	171	172	**404**	370
Change in non-cash operating working capital balances	**-**	(4)	**4**	129
Cash flow from operating activities	**171**	168	**408**	499
Investing activities				
Additions to property, plant, and equipment	**(239)**	(140)	**(389)**	(194)
Proceeds on sale of property, plant, and equipment	**5**	23	**21**	23
Equity investment *(Note 7)*	**-**	(9)	**-**	(19)
Restricted cash *(Note 6)*	**242**	28	**245**	37
Realized gains on financial instruments	**4**	-	**23**	-
Loan to equity investment *(Note 7)*	**(245)**	-	**(245)**	-
Other	**12**	(1)	**11**	(1)
Cash flow used in investing activities	**(221)**	(99)	**(334)**	(154)
Financing activities				
Decrease in short-term debt	**(137)**	(25)	**(201)**	(32)
Repayment of long-term debt *(Note 9)*	**(126)**	(11)	**(130)**	(23)
Dividends paid on common shares	**(54)**	(51)	**(105)**	(105)
Issuance of long-term debt	**502**	-	**502**	-
Redemption of preferred securities	**-**	-	**-**	(175)
Funds paid to repurchase common shares under NCIB *(Note 12)*	**(119)**	-	**(126)**	-
Net proceeds on issuance of common shares *(Note 11)*	**3**	5	**14**	10
Decrease in advances to TransAlta Power	**-**	1	**-**	2
Realized gains on financial instruments	**1**	-	**13**	-
Distributions to subsidiaries' non-controlling interests	**(27)**	(20)	**(44)**	(41)
Other	**(1)**	-	**(1)**	-
Cash flow from (used in) financing activities	**42**	(101)	**(78)**	(364)
Cash flow used in operating, investing, and financing activities	**(8)**	(32)	**(4)**	(19)
Effect of translation on foreign currency cash	**-**	6	**3**	6
Decrease in cash and cash equivalents	**(8)**	(26)	**(1)**	(13)
Cash and cash equivalents, beginning of period	**58**	79	**51**	66
Cash and cash equivalents, end of period	**$ 50**	$ 53	**$ 50**	$ 53
Cash taxes paid	**$ 14**	$ 15	**$ 60**	$ 37
Cash interest paid	**$ 48**	$ 51	**$ 67**	$ 77

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.

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.

Significant Accounting Policy Changes

On Jan. 1, 2008, the Corporation adopted two new accounting standards: Handbook Section 3862, *Financial Instruments – Disclosures* and Handbook Section 3863, *Financial Instruments – Presentation*. 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. Disclosures required as a result of adopting these Sections can be found in Note 2.

Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In 2005, the Accounting Standards Board ("AcSB") announced that accounting standards in Canada are to converge with IFRS. On Feb. 13, 2008, the AcSB confirmed that the use of IFRS will be required by Jan. 1, 2011 with appropriate comparative data from the prior year. Under IFRS, 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 that must be addressed.

On Dec. 31, 2007, the United States Securities and Exchange Commission approved rule amendments that will allow foreign private issuers to issue financial statements without reconciliation to U.S. GAAP, if they are prepared using the English language version of IFRS as issued by the International Accounting Standards Board.

TransAlta has developed a plan to transition to IFRS by January 2011. An initial investigation has been conducted to assess the implementation impacts including changes to accounting policies and processes, information systems, and business management.

A team has been established to further analyze the key areas identified in the plan and is working in conjunction with Information Technology and Internal Control resources to determine process and system changes along with appropriate financial reporting controls.

The full impact of adopting IFRS on TransAlta's future financial position and future results cannot be reasonably determined at this time. TransAlta is carefully evaluating the transitional options available under IFRS at the adoption date as well as the most appropriate long-term accounting policies.

TransAlta's preliminary view is that there are many similarities between Canadian GAAP and IFRS and that the major differences for TransAlta will likely arise in respect of property, plant, and equipment and the impairment of long-lived assets with potential impacts from expected revisions to existing IFRS standards in accounting for joint ventures and post-retirement benefits.

A steering committee has been established to monitor the progress and critical decisions in the transition to IFRS. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources, and Operations. Regular reporting is provided to the Audit and Risk Committee and the Board of Directors. Quarterly updates are provided to the Audit and Risk Committee.

2. FINANCIAL INSTRUMENTS

(A) Analysis of Financial Assets and Liabilities by Measurement Basis

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost. The disclosures in the "Financial Instruments – Recognition and Measurement" section of Note 1(T) to the Corporation's 2007 consolidated financial statements describe how the categories of financial instruments are measured and how income and expenses, including fair value gains and losses, are recognized. The following table analyses the carrying amounts of the financial assets and liabilities by category as defined by Section 3855:

Carrying value of financial instruments as at June 30, 2008

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	$ -	$ -	$ 50	$ -	$ 50
Accounts receivable	$ -	$ -	$ 540	$ -	$ 540
Risk management assets					
Current	$ 111	$ 69	$ -	$ -	$ 180
Long-term	$ 32	$ 7	$ -	$ -	$ 39
Restricted cash	$ -	$ -	$ 2	$ -	$ 2
Financial liabilities			.		
Short-term debt	$ -	$ -	$ -	$ 450	$ 450
Accounts payable and accrued liabilities	$ -	$ -	$ -	$ 539	$ 539
Risk management liabilities					
Current	$ 425	$ 84	$ -	$ -	$ 509
Long-term	$ 467	$ 8	$ -	$ -	$ 475
Long-term debt recourse[1]	$ -	$ -	$ -	$ 2,018	$ 2,018
Long-term debt non-recourse[1]	$ -	$ -	$ -	$ 240	$ 240

Carrying value of financial instruments as at Dec. 31, 2007

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	$ -	$ -	$ 51	$ -	$ 51
Accounts receivable	$ -	$ -	$ 546	$ -	$ 546
Risk management assets					
Current	$ 69	$ 24	$ -	$ -	$ 93
Long-term	$ 122	$ -	$ -	$ -	$ 122
Restricted cash	$ -	$ -	$ 242	$ -	$ 242
Financial liabilities					
Short-term debt	$ -	$ -	$ -	$ 651	$ 651
Accounts payable and accrued liabilities	$ -	$ -	$ -	$ 473	$ 473
Risk management liabilities					
Current	$ 93	$ 12	$ -	$ -	$ 105
Long-term	$ 190	$ 14	$ -	$ -	$ 204
Long-term debt recourse[1]	$ -	$ -	$ -	$ 1,618	$ 1,618
Long-term debt non-recourse[1]	$ -	$ -	$ -	$ 241	$ 241

[1] *Includes current portion.*

(B) Fair Value of Financial Instruments

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

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

I. Level Determinations and Classifications

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

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I Energy Trading fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange ("NYMEX") and the Natural Gas Exchange ("NGX"), or obtained directly from brokers, electronic exchanges such as the IntercontinentalExchange ("ICE"), or other publicly available market data providers.

Level II

Fair values are determined using inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly.

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. Level II fair values also include fair values determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, implied volatilities for options, and/or volatilities and correlations between products derived from historical prices.

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

Level III

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

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, or demand profiles.

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

The fair values of the Corporation's financial assets and liabilities are outlined below:

As at June 30, 2008	Fair value [1] Level I	Level II	Level III	Total	Total carrying value
Financial assets and liabilities measured at fair value					
Net risk management liabilities (assets) [2]	$ 857	$ (86)	$ (6)	$ 765	$ 765
Long-term debt	$ -	$ 207	$ -	$ 207	$ 207
Financial assets and liabilities measured at other than fair value					
Long-term debt	$ -	$ 2,037	$ -	$ 2,037	$ 2,051

As at Dec. 31, 2007	Fair value [1] Level I	Level II	Level III	Total	Total carrying value
Financial assets and liabilities measured at fair value					
Net risk management liabilities (assets) [2]	$ 251	$ (156)	$ (1)	$ 94	$ 94
Long-term debt	$ -	$ 310	$ -	$ 310	$ 310
Financial assets and liabilities measured at other than fair value					
Long-term debt	$ -	$ 1,577	$ -	$ 1,577	$ 1,549

[1] *Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, short-term debt, and accounts payable and accrued liabilities).*
[2] *Includes Energy Trading and Other Risk Management Assets and Liabilities on a net basis* (Note 3).

II. Fair Values Determined Using Valuation Models (Levels II & III)

Fair values determined using valuation models require the use of assumptions. Where assumptions and inputs are based on readily observable market data, the fair values are categorized as Level II. The key inputs to valuation models and regression or extrapolation formulas include interest rate yield curves, currency rates, credit spreads, implied volatilities, volatilities and correlations between products derived from historical prices, and commodity prices for similar assets or liabilities in active markets, as applicable.

Where the fair values have been developed using valuation models based on unobservable or internally developed assumptions or inputs (Level III Energy Trading Risk Management fair values), the key inputs include historical data such as plant performance, congestion on transmission paths, or demand profiles for individual non-standard deals and structured products.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined would not result in materially different fair values.

The total amount of the change in fair value estimated using a valuation technique with unobservable inputs, for financial assets and liabilities measured and recorded at fair value, that was recognized in pre-tax earnings for the six months ended June 30, 2008 was a $14 million gain. A reconciliation of the movements in Risk Management fair values by Level, as well as additional Level III gain (loss) information can be found in Note 3.

(C) Inception Gains and Losses

The majority of the Corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange requiring the use of internal valuation techniques or models.

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or based on a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the balance sheet in Energy Trading Risk Management Assets or Liabilities, and is recognized in earnings over the term of the related contracts. The difference yet to be recognized in net earnings and a reconciliation of changes during the period is as follows:

As at		**June 30, 2008**		Dec. 31, 2007
Unamortized gain at beginning of period	**$**	**5**	$	8
New transactions		**-**		4
Recognized in the Statements of Earnings during the period:				
Amortization		**(3)**		(7)
Maturity or termination		**-**		-
Change in foreign exchange rates		**-**		-
Unamortized gain at end of period	**$**	**2**	$	5

(D) Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments, as defined under Section 3862, however, for a complete understanding of the nature and extent of risks the Corporation is exposed to, this should be read in conjunction with the Corporation's discussion of Risk Management found in the 2007 Management's Discussion and Analysis section of the Annual Report.

I. Market Risk

(a) Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with expected purchase, sale or usage requirements, accordingly, these contracts, commonly termed normal purchase / normal sale ("NPNS") contracts, are not considered to be financial instruments under Section 3855. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

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

(i) Commodity Price Risk – Proprietary Trading

The Corporation's Commercial Operations & Development ("COD") segment conducts the proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Policy, the proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board of Directors approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a 3-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a 3-day measurement period implies that positions can be unwound or hedged within 3 days, however, this may not be possible if the market becomes illiquid.

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

Changes in market prices associated with proprietary trading activities affect net income in the period that the price changes occur. VaR at June 30, 2008 associated with the Corporation's proprietary trading activities was $8 million.

(ii) Commodity Price Risk - Generation

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

In addition, certain electricity sale contracts do not qualify as NPNS contracts. These contracts are designated as all-in-one hedges and are therefore accounted for as cash flow hedges under Section 3865. Unlike a typical financial derivative used in a hedging relationship, which results in a net settlement with the counterparty, these contracts will not result in a net cash outflow to the Corporation, despite their fair value currently resulting in a liability on the Corporation's balance sheet, as the Corporation will physically deliver the electricity at the price fixed under the contract, and receive cash payment for that physical delivery.

Changes in market prices associated with cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through Other Comprehensive Income ("OCI"), at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings. VaR at June 30, 2008 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $103 million.

The Corporation's policy on asset-backed transactions is to seek NPNS contract status or hedge accounting treatment. Where this is not possible, the transactions are treated as held for trading. These include, for example, positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions such as buybacks entered into to offset existing hedge positions. Changes in market prices associated with these transactions affect net earnings in the period in which the price change occurs. VaR at June 30, 2008 associated with the Corporation's commodity derivatives instruments used in the generation business, but which are not designated as hedges, was nil.

(b) Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. For a complete understanding of the nature and extent of interest rate risk the Corporation is exposed to, and how the Corporation manages this risk, refer to the discussion of Risk Management found in the 2007 Management's Discussion and Analysis section of the Annual Report.

The effect on pre-tax earnings and OCI for the six months ended June 30, 2008, due to changes in market interest rates affecting the Corporation's floating rate debt, interest bearing assets, and held for trading interest-rate derivatives outstanding at the balance sheet date, is not material.

(c) Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, and the U.S. and Australian dollars, as a result of investments and operations in foreign jurisdictions, the earnings from those operations, and the acquisition of equipment and services from foreign suppliers. For a complete understanding of the nature and extent of currency rate risk the Corporation is exposed to, and how the Corporation manages this risk, refer to the discussion of Risk Management found in the 2007 Management's Discussion and Analysis section of the Annual Report.

The foreign currency risk sensitivities required under Section 3862, and outlined below, are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency in which they are transacted and measured.

The effect on pre-tax earnings and OCI for the six months ended June 30, 2008, due to changes in the exchange rates associated with financial instruments outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a four cent increase or decrease in these currencies relative to the Canadian dollar is the most reasonably possible change and is consistent with a +/- one standard deviation move from the mean.

Currency	Net earnings decrease [1]	OCI gain[1]
Euro	$ -	$ 5
U.S.	2	3
AUD	3	-
Total	$ 5	$ 8

[1] These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect. Amounts presented are pre-tax.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in credit-worthiness of entities with which commercial exposures exist. For a complete understanding of the nature and extent of credit risk the Corporation is exposed to, and how the Corporation manages this risk, refer to the discussion of Risk Management found in the 2007 Management's Discussion and Analysis section of the Annual Report.

The Corporation's maximum exposure to credit risk at June 30, 2008, without taking into account collateral held, is represented by the current carrying amounts of accounts receivables and risk management assets as per the consolidated balance sheets. Letters of credit are the primary types of collateral held as security related to these amounts.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets that are neither past due nor impaired:

	Investment grade %	Non-investment grade %	Total %
Accounts receivable	94	6	100
Risk management assets	95	5	100

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with its trade receivables, the balance of which has not changed materially since Dec. 31, 2007.

III. Liquidity Risk

Liquidity risk is the risk that the Corporation may encounter difficulties in meeting obligations associated with financial liabilities and commitments related to collateral requirements under various contracts. For a complete understanding of the nature and extent of liquidity risk the Corporation is exposed to, and how the Corporation manages this risk, refer to the discussion of Risk Management found in the 2007 Management's Discussion and Analysis section of the Annual Report.

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

	2008	2009	2010	2011	2012	2013 and thereafter	Total
Short-term debt	$ 450	$ -	$ -	$ -	$ -	$ -	$ 450
Accounts payable and accrued liabilities	539	-	-	-	-	-	539
Long-term debt [1]	125	238	29	251	330	1,281	2,254
Energy Trading risk management liabilities [2]	262	287	185	78	15	-	827
Other risk management liabilities (assets) [3]	1	(47)	(4)	(6)	-	(6)	(62)
Total	$ 1,377	$ 478	$ 210	$ 323	$ 345	$ 1,275	$ 4,008

[1] Excludes impact of derivatives
[2] Energy Trading risk management liabilities are comprised of net risk management assets and liabilities, where the net result is a liability.
[3] Other risk management assets and liabilities are comprised of net risk management assets and liabilities, where the net result is an asset.

(E) Financial Instruments Provided as Collateral

At June 30, 2008, $130 million (Dec. 31, 2007 - $200 million) of financial assets of TransAlta Utilities Corporation ("TAU"), a wholly-owned subsidiary of TransAlta, have been pledged as collateral for $150 million of the Corporation's public debentures. In the event that TAU should default on these debentures, the debenture holders would have first claim on these assets.

At June 30, 2008, $62 million (Dec. 31, 2007 - $53 million) of financial assets related to the Corporation's proportionate share of CE Gen have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

(F) Gains and Losses on Financial Instruments

The Corporation's COD segment utilizes a variety of derivatives in its proprietary trading activities, and the related assets and liabilities are classified as held for trading. As outlined in Note 1C of the Corporation's 2007 consolidated financial statements, the net realized and unrealized gains are reported as revenues of the COD Segment. For the three months ended June 30, 2008, the COD segment recognized $45 million (June 30, 2007 - $16 million) of net realized and unrealized gains and losses. For the six months ended June 30, 2008, the COD segment recognized $60 million (June 30, 2007 - $27 million) of net realized and unrealized gains and losses *(Note 19).*

Net interest expense as reported on the consolidated statements of earnings includes interest income and expense, respectively, on the Corporation's interest bearing financial assets, primarily cash and restricted cash, and its interest bearing financial liabilities, primarily short-and long-term debt. Interest expense is calculated using the effective interest rate method (Note 9). Interest rate derivatives that are not designated as hedges are classified as held for trading with the net gain or loss also recorded in net interest expense.

Foreign exchange derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss recorded in foreign exchange gain or loss.

The net gain or loss included in earnings for the current and prior comparative periods with respect to interest rate and foreign exchange held for trading derivatives is not material.

3. RISK MANAGEMENT ASSETS AND LIABILITIES

Risk management assets and liabilities are comprised of two major types: (1) those that are used in the COD and Generation segments in relation to trading activities and certain contracting activities (Energy Trading) and (2) those used in hedging non-energy trading transactions, debt, and the net investment in self-sustaining foreign subsidiaries (Other Risk Management Assets and Liabilities).

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

As at	**June 30, 2008**			Dec. 31, 2007		
Balance Sheet - Totals	**Energy Trading**	**Other**	**Total**	Energy Trading	Other	Total
Risk management assets						
Current	**$ 112**	**$ 68**	**$ 180**	$ 34	$ 59	$ 93
Long-term	**21**	**18**	**39**	(4)	126	122
Risk management liabilities						
Current	**(485)**	**(24)**	**(509)**	(87)	(18)	(105)
Long-term	**(475)**	**-**	**(475)**	(192)	(12)	(204)
Net risk management (liabilities) assets outstanding	**$ (827)**	**$ 62**	**$ (765)**	$ (249)	$ 155	$ (94)

Energy Trading

The values of risk management assets and liabilities for Energy Trading are included on the consolidated balance sheets as follows:

As at	June 30, 2008			Dec. 31, 2007
Balance Sheet - Energy Trading	**Hedges**	**Non-hedges**	**Total**	Total related to Energy Trading
Risk management assets				
Current	**$ 43**	**$ 69**	**$ 112**	$ 34
Long-term	**14**	**7**	**21**	(4)
Risk management liabilities				
Current	**(418)**	**(67)**	**(485)**	(87)
Long-term	**(467)**	**(8)**	**(475)**	(192)
Net risk management (liabilities) assets outstanding	**$ (828)**	**$ 1**	**$ (827)**	$ (249)

The following table illustrates the disclosure on 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, 2008:

	Hedges			Non-hedges			Total		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management (liabilities) assets outstanding at Dec. 31, 2007	$ (261)	$ -	$ -	$ 10	$ 1	$ 1	$ (251)	$ 1	$ 1
Changes in net asset value attributable to:									
Market changes	(530)	3	-	(20)	3	11	(550)	6	11
New contracts entered during the period	(22)	17	-	11	2	3	(11)	19	3
Contracts settled during the period	(12)	-	-	(11)	(1)	(9)	(23)	(1)	(9)
Change in foreign exchange rates	(22)	(1)	-	-	-	-	(22)	(1)	-
Transfers in and/or out of Level III	-	-	-	-	-	-	-	-	-
Net risk management (liabilities) assets outstanding at June 30, 2008	**$ (847)**	**$ 19**	**$ -**	**$ (10)**	**$ 5**	**$ 6**	**$ (857)**	**$ 24**	**$ 6**
Additional Level III gain (loss) information:									
Total change in fair value included in OCI			$ -			$ -			$ -
Total change in fair value included in pre-tax earnings			$ -			$ 5			$ 5
Total change in fair value included in pre-tax earnings relating to those net assets held at June 30, 2008			$ -			$ 14			$ 14

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 COD 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:

		2008	2009	2010	2011	2012	2013 and thereafter	Total
Hedges	Level I	$ (268)	$ (296)	$ (190)	$ (78)	$ (15)	$ -	**$ (847)**
	Level II	6	8	5	-	-	-	**19**
	Level III	-	-	-	-	-	-	**-**
Non Hedges	Level I	$ (8)	$ (2)	-	-	-	-	**$ (10)**
	Level II	3	2	-	-	-	-	**5**
	Level III	5	1	-	-	-	-	**6**
Total	Level I	$ (276)	$ (298)	$ (190)	$ (78)	$ (15)	$ -	**$ (857)**
	Level II	9	10	5	-	-	-	**24**
	Level III	5	1	-	-	-	-	**6**
Grand Total		**$ (262)**	**$ (287)**	**$ (185)**	**$ (78)**	**$ (15)**	**$ -**	**$ (827)**

The Corporation's fixed price proprietary trading positions at June 30, 2008 and Dec. 31, 2007, were as follows:

Units (000s)	**Electricity (MWh)**	**Natural Gas (GJ)**	**Transmission (MWh)**	**Coal (Tonnes)**	**Emissions (Tonnes)**
Fixed price payor, notional amounts, June 30, 2008	**23,114**	**64,002**	**1,979**	**1,670**	**28**
Fixed price payor, notional amounts, Dec. 31, 2007	16,189	54,523	1,854	1,644	6
Fixed price receiver, notional amounts, June 30, 2008	**22,398**	**69,081**	-	**1,670**	**32**
Fixed price receiver, notional amounts, Dec. 31, 2007	16,009	61,977	-	1,644	15
Maximum term in months, June 30, 2008	**18**	**18**	**9**	**18**	**6**
Maximum term in months, Dec. 31, 2007	24	12	6	23	2

Other Risk Management Assets and Liabilities

The values of non-Energy Trading risk management assets and liabilities included on the consolidated balance sheets are as follows:

As at	**June 30, 2008**			Dec. 31, 2007
Balance Sheet - Other	**Hedges**	**Non-hedges**	**Total**	Total related to non-Energy Trading
Risk management assets				
Current	**$ 68**	**$ -**	**$ 68**	$ 59
Long-term	**18**	**-**	**18**	126
Risk management liabilities				
Current	**(7)**	**(17)**	**(24)**	(18)
Long-term	**-**	**-**	**-**	(12)
Net risk management assets (liabilities) outstanding	**$ 79**	**$ (17)**	**$ 62**	$ 155

The following table illustrates the disclosure on 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, 2008:

	Hedges[1]	Non-hedges[1]	Total
Net risk management assets (liabilities) outstanding at Dec. 31, 2007	$ 168	$ (13)	$ 155
Changes in net asset value attributable to:			
Market changes	(47)	(4)	(51)
New contracts entered during the period	7	-	7
Contracts settled during the period	(49)	-	(49)
Change in foreign exchange rates	-	-	-
Net risk management assets (liabilities) outstanding at June 30, 2008	**$ 79**	**$ (17)**	**$ 62**

[1] All Other Risk Management Assets and Liabilities are classified as Level II.

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 or reduction in the net investment.

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

	2008	2009	2010	2011	2012	2013 and thereafter	Total
Hedges	$ -	$ 63	$ 4	$ 6	$ -	$ 6	**$ 79**
Non-hedges	(1)	(16)	-	-	-	-	**(17)**
Grand Total	**$ (1)**	**$ 47**	**$ 4**	**$ 6**	$ -	**$ 6**	**$ 62**

Credit Risk Management

The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Generation Power Purchase Arrangements ("PPA") as receivables are substantially all secured by letters of credit.

The maximum credit exposure to any one customer for commodity trading and origination, excluding the California market receivables and including the fair value of open trading positions, at June 30, 2008 was $39 million (Dec. 31, 2007 - $6 million).

4. HEDGING ACTIVITIES

Derivative and non-derivative financial instruments are used to manage exposures to interest, commodity prices, currency, credit, and other market risks. When derivatives are used to manage the Corporation's own exposures, the Corporation determines for each derivative whether hedge accounting can be applied. Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency 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

Interest rate swaps are used to hedge exposures to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates. Foreign exchange contracts are also used to hedge foreign currency denominated assets and liabilities.

No ineffective portion of fair value hedges was recorded for the three and six months ended June 30, 2008 and June 30, 2007.

Cash flow hedges

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

For the three months ended June 30, 2008, a pre-tax unrealized loss of $362 million (June 30, 2007 - $119) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $19 million (June 30, 2007 - $5 million) related to amounts previously related to OCI was reclassified to net earnings.

For the six months ended June 30, 2008, a pre-tax unrealized loss of $591 million (June 30, 2007 - $246 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $36 million (June 31, 2007 - $3 million) related to amounts previously related to OCI was reclassified to net earnings. No net unrealized gain or loss was recognized in earnings for the ineffective portion.

Over the next 12 months, the Corporation estimates that $247 million of after-tax losses will be reclassified from Accumulated Other Comprehensive Income ("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. These contracts have a maximum duration of five years.

Net investment hedges

Foreign exchange contracts and foreign currency-denominated liabilities are used to manage the Corporation's foreign currency exposures to net investments in self-sustaining foreign operations having a functional currency other than the Canadian dollar. Foreign denominated expenses are also used to assist in managing foreign currency exposures on earnings from self-sustaining foreign operations.

For the three months ended June 30, 2008, the net after-tax loss of $3 million (June 30, 2007 - nil), relating to the net investment in foreign operations, net of hedging, was recognized in OCI. For the six months ended June 30, 2008, the net after-tax loss of $8 million (June 30, 2007 - $2 million), relating to the net investment in foreign operations, net of hedging, 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.

As at	June 30, 2008					Dec. 31, 2007
	Fair Value Hedges	**Cash Flow Hedges**	**Net Investment Hedges**	**Not Designated in a hedging relationship**	**Total**	Total
Financial Assets						
Derivative instruments	**$ 6**	**$ 64**	**$ 73**	**$ 76**	**$ 219**	$ 215
Financial Liabilities						
Derivative instruments	**$ -**	**$ (888)**	**$ (4)**	**$ (92)**	**$ (984)**	$ (309)

U.S. dollar denominated debt with a face value of U.S.$1.2 billion has been designated as a part of the hedge of TransAlta's self-sustaining foreign operations.

5. INVENTORY

Inventory represents coal and natural gas fuels which are valued at the lower of cost and net realizable value. The classifications are as follows:

As at	**June 30, 2008**	Dec. 31, 2007
Coal	**$ 61**	$ 23
Natural gas	**6**	7
Purchased emission credits	**1**	-
Total	**$ 68**	$ 30

The increase in coal inventory at June 30, 2008 compared to Dec. 31, 2007 is primarily due to lower production at the Alberta Thermal plants and Centralia Thermal plant.

The change in inventory is outlined below:

Balance, Dec. 31, 2007	$ 30
Net additions	37
Change in foreign exchange rates	1
Balance, June 30, 2008	**$ 68**

No inventory is pledged as security for liabilities.

For the three months and six months ended June 30, 2008, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into earnings.

6. RESTRICTED CASH

Restricted cash is comprised of debt service funds which are legally restricted, and require the maintenance of specific minimum balances equal to the next debt service payment, and amounts restricted for capital and maintenance expenditures.

The change in restricted cash is outlined below:

Balance, Dec. 31, 2007	$	242
Amount returned to TransAlta		(245)
Change in foreign exchange rates		5
Balance, June 30, 2008	**$**	**2**

During the 3 months ended June 30, 2008, a subsidiary closed its position under a credit derivative agreement. The investment in Notes held in Trust as security for the subsidiary's obligation under this agreement was returned to the subsidiary.

7. INVESTMENTS

Investments mainly represent TransAlta's investment in the Corporation's wholly owned Mexican operations. As required under Accounting Guideline 15, *Consolidation of Variable Interest Entities*, of the CICA, TransAlta's Mexican operations are accounted for as equity subsidiaries. On Feb. 20, 2008, TransAlta announced the sale of the Mexican operations to InterGen Global Ventures B.V. ('InterGen") for U.S.$303.5 million. Due to the process needed to adjust various contracts related to gas pricing regulatory changes in Mexico, the transaction is expected to close before the end of the third quarter of 2008. TransAlta recorded a charge to the first quarter earnings of $65 million, net of tax, to reflect the estimated difference between the net carrying value and anticipated net sale price of these assets. The gross charge of $93 million is recorded in equity loss.

The change in investments is shown below:

Opening balance, Dec. 31, 2007	$	125
Equity losses		(97)
Loan to equity investment		245
Other		(2)
Closing balance, June 30, 2008	**$**	**271**

8. ASSETS HELD FOR SALE

During the six months ended June 30, 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million; the remainder of the mining and reclamation equipment was reclassified to property, plant, and equipment as it is being retained for reclamation activities.

9. LONG-TERM DEBT AND NET INTEREST EXPENSE

Amounts Outstanding	June 30, 2008			Dec. 31, 2007		
	Carrying value	**Cost**	**Interest** [1]	Carrying value	Cost	Interest [1]
Debentures, due 2008 to 2033	**$ 837**	**$ 831**	**6.5%**	$ 956	$ 946	6.5%
Senior Notes, (2008 - US$1,100 million, 2007 - US$600 million)	**1,112**	**1,114**	**6.4%**	588	586	6.3%
Non-recourse	**240**	**240**	**7.4%**	242	242	7.4%
Notes payable - Windsor plant	**40**	**40**	**7.4%**	43	43	7.4%
Commercial Loan Obligation	**29**	**29**	**5.9%**	30	30	5.9%
	2,258	**2,254**		1,859	1,847	
Less: current portion	**(134)**	**(134)**		(154)	(154)	
Total long-term debt	**$ 2,124**	**$ 2,120**		$ 1,705	$ 1,693	

[1] *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*

The Corporation has converted $100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of receive fixed pay floating interest rate swaps. These interest rate swaps mature in 2011. In addition, the Corporation converted U.S.$100 million fixed interest rate debt with a rate of 6.65 per cent to floating rates through the use of receive fixed pay floating interest rate swaps. These interest rate swaps mature in 2018.

On May 9, 2008, the Corporation issued debentures in the amount of U.S.$500 million. The debentures bear interest at a rate of 6.65 per cent and mature in 2018.

Interest Expense

	3 months ended June 30		6 months ended June 30	
	2008	2007	**2008**	2007
Interest on long-term debt	**$ 36**	$ 37	**$ 68**	$ 76
Interest on short-term debt	**6**	6	**16**	13
Interest income	**(4)**	(6)	**(9)**	(14)
Capitalized interest	**(3)**	-	**(7)**	(1)
Net interest expense	**$ 35**	$ 37	**$ 68**	$ 74

The Corporation capitalizes interest during the construction phase of longer-term capital projects.

10. ASSET RETIREMENT OBLIGATIONS

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

Balance, Dec. 31, 2007	$ 276
Liabilities incurred in period	2
Liabilities settled in period	(12)
Accretion expense	11
Revisions in estimated cash flows	1
Change in foreign exchange rates	3
Balance, June 30, 2008	**$ 281**
Less current portion	(44)
	$ 237

The Corporation 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.

11. 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, 2008, the Corporation had 197.6 million (Dec. 31, 2007 – 200.9 million) common shares issued and outstanding. During the three months ended June 30, 2008, 0.1 million shares (2007 – 0.3 million), were issued for proceeds of $3 million (2007 – $5 million). During the six months ended June 30, 2008, 0.5 million shares (2007 – 0.5 million), were issued for proceeds of $14 million (2007 – $10 million).

During the three and six months ended June 2008, 2.0 million and 3.9 million shares, respectively, were cancelled under the Normal Course Issuer Bid ("NCIB") program.

B. Stock options

On Feb. 1, 2008, 1.0 million stock options were granted at a strike price of $31.97 on the Toronto Stock exchange ("TSX") for Canadian employees and U.S.$31.83 on the New York Stock Exchange ("NYSE") for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire after 10 years *(Note 20).*

At June 30, 2008, the Corporation had 1.8 million outstanding employee stock options (Dec. 31, 2007 - 1.2 million). For the three months ended June 30, 2008, 0.1 million options with a weighted average exercise price of $20.33 were exercised resulting in 0.1 million shares issued. 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, 2008, 0.3 million options with a weighted average exercise price of $20.62 were exercised resulting in 0.3 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $26.40. 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.

12. SHAREHOLDERS' EQUITY

	Common shares	Retained earnings	Accumulated Other Comprehensive (Loss) / Income	Total shareholders' equity
Balance, Dec. 31, 2007	$ 1,781	$ 763	$ (245)	$ 2,299
Net earnings for the 6 months ended June 30, 2008	-	80	-	80
Common shares issued (dividends declared)	14	(108)	-	(94)
Shares purchased under NCIB	(35)	(95)	-	(130)
Losses on translating financial statements of self-sustaining foreign operations	-	-	(8)	(8)
Losses on derivatives designated as cash flow hedges	-	-	(388)	(388)
Derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net earnings in the current period	-	-	28	28
Balance, June 30, 2008	**$ 1,760**	**$ 640**	**$ (613)**	**$ 1,787**

Normal course issuer bid program

On May 5, 2008, TransAlta announced a continuation of the Corporation's NCIB program. The Corporation may purchase, for cancellation, up to 19.9 million of its common shares or approximately 10 per cent of the 199 million common shares issued and outstanding as at April 23, 2008. The renewed NCIB program will continue until May 5, 2009. Purchases have been made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the three and six months ended June 30, 2008, the Corporation purchased 1,977,500 and 3,886,400 shares, respectively, at an average price of $35.40 and $33.45 per share, respectively. The units were purchased for an amount higher than their weighted average book value per share ($8.96 and $8.95 per share, respectively) resulting in a reduction of retained earnings of $52 million and $95 million, respectively. Due to the timing of payments to repurchase common shares under the NCIB, $53 million was paid in April 2008 that was related to the previous quarter.

	3 months ended June 30, 2008	6 months ended June 30, 2008
Total shares purchased	1,977,500	3,886,400
Average purchase price per share	$ 35.40	$ 33.45
Total cost	$ 70	$ 130
Weighted average book value of shares cancelled	18	35
Reduction to retained earnings	**$ 52**	**$ 95**

13. CAPITAL

TransAlta's components of capital are listed below:

As at	June 30, 2008	Dec. 31, 2007	Increase / (Decrease)
Short-term debt including current portion of long-term debt	**$ 584**	$ 805	$ (221)
Less: cash and cash equivalents	**(50)**	(51)	1
	534	754	(220)
Long-term debt			
Recourse	**1,913**	1,496	417
Non-recourse	**211**	209	2
Non-controlling interests	**485**	496	(11)
Common shareholders' equity			
Common shares	**1,760**	1,781	(21)
Retained earnings	**640**	763	(123)
AOCI	**(613)**	(245)	(368)
	4,396	4,500	(104)
Total Capital	**$ 4,930**	$ 5,254	$ (324)

TransAlta's objectives and strategy in managing capital have remained unchanged from Dec. 31, 2007.

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

	June 30, 2008	Dec. 31, 2007	Target
Cash flow to interest (times)	**6.8**	6.6	Minimum of 4
Cash flow to total debt (%)	**31.7**	30.7	Minimum of 25
Debt to invested capital (%)	**53.9**	46.8	Maximum of 55

Transalta also ensures sufficient cash and credit is available to fund operations, pay dividends, and invest in capital assets.

These amounts are summarized in the table below:

	3 months ended June 30			6 months ended June 30		
	2008	2007	Increase/ (Decrease)	**2008**	2007	Increase/ (Decrease)
Cash flow from operating activities	**$ 171**	$ 168	$ 3	**$ 408**	$ 499	$ (91)
Dividends paid	**(54)**	(51)	(3)	**(105)**	(105)	-
Capital asset expenditures	**(239)**	(140)	(99)	**(389)**	(194)	(195)
Net cash (outflow) inflow	**$ (122)**	$ (23)	$ (99)	**$ (86)**	$ 200	$ (286)

For the three months and six months ended June 30, 2008 the decrease in the total net cash flows primarily resulted from higher capital expenditures on growth and less favorable working capital movements.

The financial terms and conditions of the Corporation's debentures and credit facilities remain unchanged from Dec. 31, 2007.

TransAlta's formal dividend policy targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings. TransAlta's management defines comparable earnings as net earnings adjusted for items that are expected to be non-recurring in the future.

14. RELATED PARTY TRANSACTIONS

On Dec.16, 2006, TAU entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the new coal-fired plant. The joint venture project is held in a partnership with TransAlta Energy Corporation ("TEC"), a wholly-owned subsidiary of TransAlta, and EPCOR. TAU will supply coal until the earlier of the Keephills 3 facility permanently ceasing operations or the termination of the agreement by TAU and the partners of the joint venture. As at June 30, 2008, TAU had received $22 million from Keephills 3 Limited Partnership, a wholly-owned subsidiary of TransAlta, as a pre-payment of coal to be delivered under the contract. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011.

In August 2006, TransAlta entered into an agreement with CE Gen, a Corporation jointly controlled by TransAlta and MidAmerican Energy Holdings Company ("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, TransAlta Cogeneration, L.P. ("TA Cogen") entered into various transportation swap transactions with 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.

15. 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.

16. COMMITMENTS

During the second quarter of 2008, Transalta entered into five-year agreements with Bonneville Power Administration Transmission ("BPAT") to purchase 400 MW of Pacific Northwest transmission network capacity. Provided BPAT can meet certain conditions for delivering the service, the Corporation is committed to taking the services at BPAT's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed. The obligation under these agreements is expected to be U.S.$46 million for the five-year period.

On May 27, 2008, TransAlta announced a 66 MW expansion of its Summerview wind farm located in southern Alberta near Pincher Creek. The capital cost of the project is estimated at $123 million with construction commencing in the second quarter of 2009 and commercial operations expected to begin in the first quarter of 2010.

On April 21, 2008, TransAlta announced a 53 MW efficiency uprate at TransAlta's Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009. As at June 30, 2008, total capital spend on this project was $9 million.

On Feb. 13, 2008, TransAlta announced plans to design, build, and operate Blue Trail, a 66 MW wind power project in southern Alberta. The capital cost of the project is estimated at $115 million. Commercial operations are expected to commence in the fourth quarter of 2009. As at June 30, 2008, total capital spend on this project was $24 million.

On June 21, 2007, TAU 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 $121 million for the purchase of the equipment, and an additional $29 million for the assembly and commissioning of the dragline, for a total of approximately $150 million, with final payments for goods and services due by May 2010. Total payments under this agreement during the three months and six months ended June 30, 2008 were $22 million and $43 million, respectively.

Keephills 3 plant construction and associated mine capital costs via the Keephills 3 Limited Partnership are anticipated to be approximately $1.6 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $800 million. As at June 30, 2008, total spend on this project was $283 million.

On Jan. 19, 2007, TransAlta announced a 25-year contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 75 MW of wind power. TransAlta will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills"). Commercial operations are expected to begin by the end of 2008. On July 17, 2007, TransAlta amended the power purchase agreement with New Brunswick Power to increase capacity under the agreement from 75 MW to 96 MW. Total capital costs for the Kent Hills wind power project will be approximately $170 million. As at June 30, 2008, total capital spend for the Kent Hills wind power project was $50 million. TransAlta 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 acquired Canadian Hydro's Fairfield Hill wind power site, including the option to develop the site at a future date, for $1 million. Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

17. 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 U.S.$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 U.S.$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. On Aug. 24, 2007, the U.S. Court of Appeals for the Ninth Circuit granted the appeal. TransAlta has requested rehearing, however, FERC has yet to make a ruling on such a request and such a decision is not expected in the near future.

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. The Ninth

Circuit held that FERC's authorization of market-based rate tariffs in these proceedings complied with the FPA, but that FERC erred in refusing refunds on the grounds that it lacked authority to order refunds for violations of its reporting requirement and remanded the case for further refund proceedings. The court did not itself order any refunds, leaving it to FERC to consider appropriate remedial options.

On March 21, 2008, FERC issued an Order on Remand establishing a refund hearing before an Administrative Law Judge to determine whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable in California during the 2000-2001 period.

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.

18. GUARANTEES – LETTERS OF CREDIT

Letters of credit are issued to counterparties that have credit exposure to certain subsidiaries. If the Corporation or its subsidiary does not pay amounts due under the contract, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at June 30, 2008 totalled $828 million (Dec. 31, 2007 - $550 million) with nil (Dec. 31, 2007 – nil) amounts exercised by third parties under these arrangements.

TransAlta letters of credit do not contain recourse provisions nor does the Corporation hold any assets as collateral against the guarantees issued.

19. SEGMENTED DISCLOSURES

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

3 months ended June 30, 2008	**Generation**	**COD**	**Corporate**	**Total**
Revenues	**$ 663**	**$ 45**	**$ -**	**$ 708**
Fuel and purchased power	**(332)**	**-**	**-**	**(332)**
Gross margin	**331**	**45**	**-**	**376**
Operations, maintenance, and administration	**139**	**10**	**29**	**178**
Depreciation and amortization	**96**	**1**	**3**	**100**
Taxes, other than income taxes	**5**	**-**	**-**	**5**
Intersegment cost allocation	**8**	**(8)**	**-**	**-**
Operating expenses	**248**	**3**	**32**	**283**
Operating income (loss)	**$ 83**	**$ 42**	**$ (32)**	**$ 93**
Net interest expense *(Note 9)*				**(35)**
Earnings before non-controlling interests and income taxes				**$ 58**

3 months ended June 30, 2007	Generation	COD	Corporate	Total
Revenues	$ 596	$ 16	$ -	$ 612
Fuel and purchased power	(256)	-	-	(256)
Gross margin	340	16	-	356
Operations, maintenance, and administration	130	8	22	160
Depreciation and amortization	96	1	3	100
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation	7	(7)	-	-
Operating expenses	238	2	25	265
Operating (loss) income	$ 102	$ 14	$ (25)	$ 91
Foreign exchange gain				5
Gain on sale of equipment *(Note 8)*				12
Net interest expense *(Note 9)*				(37)
Equity loss *(Note 7)*				(2)
Earnings before non-controlling interests and income taxes				$ 69

6 months ended June 30, 2008	**Generation**	**COD**	**Corporate**	**Total**
Revenues	**$ 1,451**	**$ 60**	**$ -**	**$ 1,511**
Fuel and purchased power	**(702)**	**-**	**-**	**(702)**
Gross margin	**749**	**60**	**-**	**809**
Operations, maintenance, and administration	**239**	**20**	**54**	**313**
Depreciation and amortization	**196**	**1**	**7**	**204**
Taxes, other than income taxes	**10**	**-**	**-**	**10**
Intersegment cost allocation	**15**	**(15)**	**-**	**-**
Operating expenses	**460**	**6**	**61**	**527**
Operating income (loss)	**$ 289**	**$ 54**	**$ (61)**	**$ 282**
Foreign exchange loss				**(1)**
Gain on sale of equipment *(Note 8)*				**5**
Net interest expense *(Note 9)*				**(68)**
Equity loss *(Note 7)*				**(97)**
Earnings before non-controlling interests and income taxes				**$ 121**

6 months ended June 30, 2007	Generation	COD	Corporate	Total
Revenues	$ 1,254	$ 27	$ -	$ 1,281
Fuel and purchased power	(547)	-	-	(547)
Gross margin	707	27	-	734
Operations, maintenance, and administration	233	17	45	295
Depreciation and amortization	192	1	6	199
Taxes, other than income taxes	11		-	11
Intersegment cost allocation	14	(14)	-	-
Operating expenses	450	4	51	505
Operating income (loss)	$ 257	$ 23	$ (51)	$ 229
Foreign exchange gain				5
Gain on sale of equipment *(Note 8)*				12
Net interest expense *(Note 9)*				(74)
Equity loss *(Note 7)*				(11)
Earnings before non-controlling interests and income taxes				$ 161

II. Selected balance sheet information

As at June 30, 2008	**Generation**	**COD**	**Corporate**	**Total**
Goodwill	**$ 97**	**$ 30**	**$ -**	**$ 127**
Total segment assets	**$ 6,198**	**$ 298**	**$ 1,058**	**$ 7,554**

As at Dec. 31, 2007				
Goodwill	$ 95	$ 30	$ -	$ 125
Total segment assets	$ 5,950	$ 147	$ 1,082	$ 7,179

An increase in foreign exchange rates has resulted in a $2 million change in goodwill. A portion of goodwill is related to CE Gen and is therefore denominated in U.S. dollars. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation loss is reflected in AOCI.

III. Selected cash flow information

3 months ended June 30, 2008	**Generation**	**COD**	**Corporate**	**Total**
Capital expenditures	**$ 235**	**$ 2**	**$ 2**	**$ 239**

3 months ended June 30, 2007				
Capital expenditures	$ 135	$ 1	$ 4	$ 140

6 months ended June 30, 2008	**Generation**	**COD**	**Corporate**	**Total**
Capital expenditures	**$ 383**	**$ 3**	**$ 3**	**$ 389**

6 months ended June 30, 2007				
Capital expenditures	$ 185	$ 2	$ 7	$ 194

IV. Depreciation and amortization expense per statement of cash flows

The reconciliation between depreciation expense on the statements of earnings and statements of cash flows is presented below:

	3 months ended June 30		**6 months ended June 30**	
	2008	2007	**2008**	2007
Depreciation and amortization expense for reportable segments	**$ 100**	$ 100	**$ 204**	$ 199
Mining equipment depreciation, included in fuel and purchased power	**10**	6	**18**	13
Accretion expense, included in depreciation and amortization expense	**(6)**	(6)	**(11)**	(12)
Depreciation and amortization expense per statements of cash flows	**$ 104**	$ 100	**$ 211**	$ 200

20. STOCK-BASED COMPENSATION

The Corporation uses the fair value method of accounting for awards granted under its fixed stock option plans and its performance stock option plan. On Feb. 1, 2008, 1.0 million stock options were granted at a strike price of $31.97 on the Toronto Stock exchange (“TSX”) for Canadian employees and U.S.$31.83 on the New York Stock Exchange (“NYSE”) for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire after 10 years. The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model and the following assumptions, resulting in a fair value of $6.31 per option:

Risk free interest rate (%)	3.6
Expected life of the options (years)	7
Dividend rate (%)	3.4
Volatility in the price of the corporation's shares (%)	23.2

For the three and six months ended June 30, 2008, the total stock option expense recorded in operations, maintenance, and administration expense was $1 million and $2 million, respectively.

21. 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, 2008	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 1**	**$ 1**	**$ -**	**$ 2**
Interest cost	**5**	**-**	**1**	**6**
Expected return on plan assets	**(6)**	**-**	**-**	**(6)**
Experience loss	**1**	**-**	**-**	**1**
Amortization of net transition (asset) obligation	**(3)**	**-**	**-**	**(3)**
Defined benefit (income) expense	**(2)**	**1**	**1**	**-**
Defined contribution option expense of registered pension plan	**4**	**-**	**-**	**4**
Net expense	**$ 2**	**$ 1**	**$ 1**	**$ 4**

3 months ended June 30, 2007	Registered	Supplemental	Other	Total
Current service cost	$ 1	$ 1	$ -	$ 2
Interest cost	5	-	1	6
Expected return on plan assets	(6)	-	-	(6)
Amortization of net transition (asset) obligation	(3)	-	-	(3)
Defined benefit (income) expense	(3)	1	1	(1)
Defined contribution option expense of registered pension plan	4	-	-	4
Net expense	$ 1	$ 1	$ 1	$ 3

6 months ended June 30, 2008	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 2**	**$ 1**	**$ 1**	**$ 4**
Interest cost	**10**	**1**	**1**	**12**
Expected return on plan assets	**(12)**	**-**	**-**	**(12)**
Experience loss	**1**	**-**	**-**	**1**
Amortization of net transition (asset) obligation	**(5)**	**-**	**-**	**(5)**
Defined benefit (income) expense	**(4)**	**2**	**2**	**-**
Defined contribution option expense of registered pension plan	**9**	**-**	**-**	**9**
Net expense	**$ 5**	**$ 2**	**$ 2**	**$ 9**

6 months ended June 30, 2007	Registered	Supplemental	Other	Total
Current service cost	$ 2	$ 1	$ 1	$ 4
Interest cost	10	1	1	12
Expected return on plan assets	(12)	-	-	(12)
Amortization of net transition (asset) obligation	(5)	-	-	(5)
Defined benefit (income) expense	(5)	2	2	(1)
Defined contribution option expense of registered pension plan	10	-	-	10
Net expense	$ 5	$ 2	$ 2	$ 9

22. SUBSEQUENT EVENTS

Potential breach of Keephills ash lagoon

On July 26, 2008, TransAlta detected a crack in the dyke wall at the Keephills ash lagoon. The Corporation immediately notified Alberta Environment and the local authorities, and began taking measures to control and mitigate the effects of any potential breach and release of water from the lagoon. There are no residents in the vicinity and TransAlta is restricting access to the area to ensure no one is at risk. The Corporation will provide further updates on the situation as it becomes available.

LS Power and Global Infrastructure Approach TransAlta to Discuss Potential Transaction

On July 18, 2008, the Corporation had received a non-binding letter from LS Power Equity Partners, an entity associated with Luminus Management LLC, and Global Infrastructure Partners regarding engaging in a dialogue about a possible acquisition of TransAlta for $39 per share in cash. TransAlta's Board of Directors will carefully consider the letter and respond in due course.

Debentures

On July 17, 2008, Transalta was advised by the holder of $100 million of debentures held by TAU that they intend to redeem the debentures on July 31, 2008. The debentures were issued at a fixed interest rate of 5.49 per cent, maturing in 2023 and redeemable at the option of the holder in 2008 at a price of $98.45 per $100 of notional.

Carbon Capture

On July 8, 2008, the Alberta government announced its commitment to provide $2 billion in funding for the development of Carbon Capture and Storage (“CCS”) technology. This funding initiative is key to accelerating CCS projects across Alberta and in particular, TranAlta’s chilled ammonia CCS pilot project with Alstom Canada announced in April 2008. TransAlta intends to apply for funding support.

23. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

SUPPLEMENTAL INFORMATION

(Annualized)		June 30, 2008	Dec. 31, 2007
Closing market price		$ 36.86	$ 33.35
Price range (last 12 months)	High	$ 37.25	$ 34.00
	Low	$ 27.32	$ 23.76
Debt/invested capital (including non recourse debt)		53.9%	46.8%
Debt/invested capital (excluding non recourse debt)		51.6%	44.2%
Return on common shareholders' equity		14.2%	13.1%
Return on invested capital		9.9%	9.8%
Comparable return on invested capital		11.9%	9.7%
Cash dividends per share		$ 1.04	$ 1.00
Price/earnings ratio (times)		26.8 x	21.8 x
Earnings coverage		3.0 x	3.3 x
Dividend payout ratio (based on net earnings)		76.0%	65.6%
Dividend payout ratio (based on comparable earnings)		66.7%	76.6%
Dividend coverage (times)		3.6 x	4.2 x
Dividend yield		2.8%	3.0%
Cash flow to debt		31.7%	30.7%
Cash flow to interest coverage (times)		6.8 x	6.6 x

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 / 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

Comparable return on invested capital = (comparable earnings before non-controlling interests and income taxes + net interest expense) / average annual invested capital

Price/earnings ratio = current year's close / basic earnings per share

Earnings coverage = (net earnings + income taxes + net interest expense) / (net interest expense excluding capitalized interest)

Dividend payout ratio = dividends / net earnings or comparable earnings

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

Dividend yield = dividend per common share / current period's close price

Cash flow to debt = cash flow from operating activities before changes in working capital / two-year average of total debt

Cash flow to interest (times) = (cash flow from operating activities before changes in working capital + net interest expense) / (net interest expense excluding capitalized interest)

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, regardless of 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 mega watts, 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/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW) - A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) - A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

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

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

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