TRANSALTA CORPORATION

FIRST QUARTER REPORT FOR 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 21 for additional information.

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements of TransAlta Corporation as at and for the three months ended March 31, 2007 and 2006, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in our annual report for the year ended Dec. 31, 2006. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated April 23, 2007. Additional information respecting TransAlta, including its annual information form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have two business segments: Generation and Corporate Development & Marketing ("CD&M"). Our segments are supported by a corporate group that provides finance, treasury, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, and other administrative support.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items is reflected in the equity section of the consolidated balance sheets.

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

3 months ended March 31		**2007**		2006
Availability (%)		**88.2**		96.9
Production (GWh)		**12,697**		12,444
Revenue	**$**	**723.7**	$	733.7
Gross margin[1]	**$**	**391.7**	$	394.0
Operating income [1]	**$**	**152.1**	$	154.0
Net earnings	**$**	**66.0**	$	69.2
Basic and diluted earnings per common share	**$**	**0.33**	$	0.35
Cash flow from operating activities	**$**	**330.8**	$	200.7

[1] *Gross margin and Operating income are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 18 of this MD&A for a further discussion of Operating income and Gross margin, including a reconciliation to net earnings.*

		3 months ended March 31, 2007		Year ended Dec. 31, 2006
Total assets	**$**	**7,252.9**	$	7,460.1
Total long-term financial liabilities	**$**	**3,297.9**	$	3,094.1
Cash dividends declared per share	**$**	**0.25**	$	1.00

AVAILABILITY & PRODUCTION

Availability for the three months ended March 31, 2007 decreased to 88.2 per cent from 96.9 per cent compared to the same period in 2006 primarily due to derating at the Centralia coal-fired plant ("Centralia Coal") due to test burns of Power River Basin ("PRB") coal and higher planned and unplanned outages at the Alberta Thermal plants ("Alberta Thermal") and higher unplanned outages at the Centralia gas-fired plant ("Centralia Gas").

Production for the first quarter increased 253 gigawatt hours ("GWh") compared to the same period in 2006 as a result of increased production at various gas facilities and Genesee 3 partially offset by higher planned and unplanned outages at Alberta Thermal and lower hydro production.

NET EARNINGS

For the three months ended March 31, 2007, reported net earnings decreased to $66.0 million from $69.2 million compared to the same period in 2006. For the three months ended March 31, 2007, comparable earnings[1] were $66.0 million ($0.33 per common share) compared to $75.4 million ($0.38 per common share) in the same period in 2006.

A reconciliation of net earnings is presented below:

Net earnings, 2006	$	69.2
Decrease in Generation gross margins		(3.5)
Increase in CD&M margins		1.2
Increase in operations, maintenance and administration costs		(2.1)
Decrease in depreciation expense		2.5
Decrease in net interest expense		3.2
Increase in equity loss		(7.9)
Decrease in non-controlling interest		2.9
Increase in income tax expense		(0.2)
Other		0.7
Net earnings, 2007	**$**	**66.0**

Generation gross margins decreased by $3.5 million for the three months ended March 31, 2007 as a result of higher planned and unplanned outages and increased coal costs at Alberta Thermal and lower margins at Ottawa. These decreases were partially offset by favourable pricing in the Alberta market and at Centralia Coal combined with lower fuel costs at Centralia Coal.

CD&M gross margins increased $1.2 million for the three months ended March 31, 2007 compared to the same period in 2006 due to higher gains from trading activities in the western region.

Operations, maintenance and administration ("OM&A") costs for the three months ended March 31, 2007 increased by $2.1 million mainly due to increased investment in our information technology infrastructure.

Depreciation expense decreased $2.5 million for the three months ended March 31, 2007 compared to 2006 primarily due to an impairment recorded on turbines held in inventory in the first quarter of 2006 partially offset by retirement of parts replaced during planned maintenance in 2007 and increased depreciation across the fleet.

For the three months ended March 31, 2007, net interest expense declined $3.2 million mainly due to lower long-term debt levels and higher

1 Comparable earnings is not defined under Canadian GAAP. Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section on page 18 of this MD&A for further discussion of comparable earnings, including reconciliation to net earnings.

interest income on cash deposits partially offset by higher interest on short-term debt balances and the unwinding of a net investment hedge in 2006. For the three months ended March 31, 2007, net debt of $18.8 million and preferred securities of $175.0 million were repaid.

For the three months ended March 31, 2007, equity loss increased $7.9 million due to lower margins, increased depreciation, and higher interest expense.

For the three months ended March 31, 2007, non-controlling interests decreased by $2.9 million compared to the same period in 2006 due to lower earnings at TransAlta Cogeneration, L.P. ("TA Cogen") as a result of lower margins at Ottawa.

Income taxes were comparable to the same period in 2006 as the impact of lower pre-tax earnings was offset by the effect of jurisdictions in which income is earned. The effective tax rates for the quarter ended March 31, 2007 was 26.7 per cent compared to 23.2 per cent for the same period in 2006.

CASH FLOW

Cash flow from operating activities for the three months ended March 31, 2007 increased $130.1 million compared to the same period in 2006 mainly due to changes in working capital partially offset by lower cash earnings. In the first quarter of 2007, $185 million of contractually scheduled payments related to 2006 were collected. In the third quarter we will only receive two month's worth of revenue under our Power Purchase Agreements ("PPAs") due to timing of scheduled payments. Further, in the fourth quarter a payment relating to 2007 PPA revenues will not be received until Jan. 2, 2008.

The key factors responsible for these changes are listed below in the reconciliation of cash flow from operating activities for the three months ended March 31, 2006 to 2007:

Cash flow from operating activities for 3 months ended March 31, 2006	$ 200.7
Decreased cash earnings	(19.3)
Collection of receivables related to 2006 revenue	185.0
Changes in non-cash working capital	(35.6)
Cash flow from operating activities for 3 months ended March 31, 2007	**$ 330.8**

At March 31, 2007, our total debt (including non-recourse debt) to invested capital ratio[1] was 41.4 per cent (37.5 per cent excluding non-recourse debt). This represents a slight increase over the Dec. 31, 2006 ratio of 40.9 per cent (36.9 per cent excluding non-recourse debt).

SIGNIFICANT EVENTS

Three months ended March 31, 2007

2007 Canadian Federal Budget

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

Greenhouse Gas Emissions Standards

On March 8, 2007, the Government of Alberta introduced the Climate Change and Emissions Management Amendment Act which outlines the proposed approach to greenhouse gas emissions, effective July 1, 2007. Under the proposed legislation, the baselines and targets for greenhouse gas emissions intensity are set on a facility by facility basis. TransAlta anticipates being able to meet these requirements as currently proposed.

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[1] This ratio is further defined on page 39

On April 12, 2007, Washington State passed Bill 6001 designed to address climate change. Regulations are to be developed over the next year. At this stage it is not clear if the future regulations under the Bill will affect TransAlta's operations at Centralia, or whether the plant will be subject to exemption.

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

Keephills 3 Power Plant

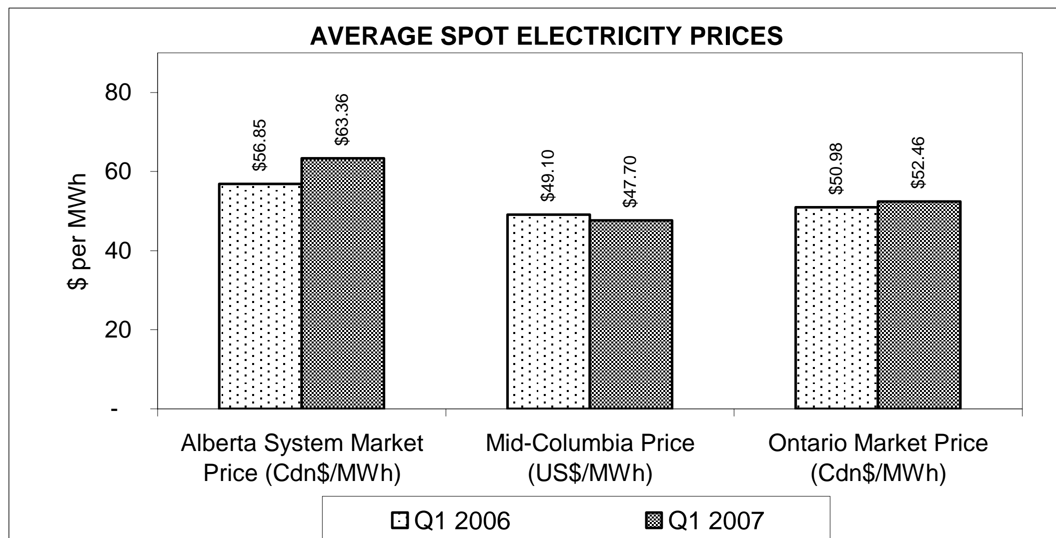
On Feb. 26, 2007, TransAlta announced that we will proceed with building the 450 MW Keephills 3 coal-fired power plant. The plant will be developed jointly by EPCOR Utilities Inc. ("EPCOR") and TransAlta. The capital cost of the project is expected to be approximately $1.6 billion, including associated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

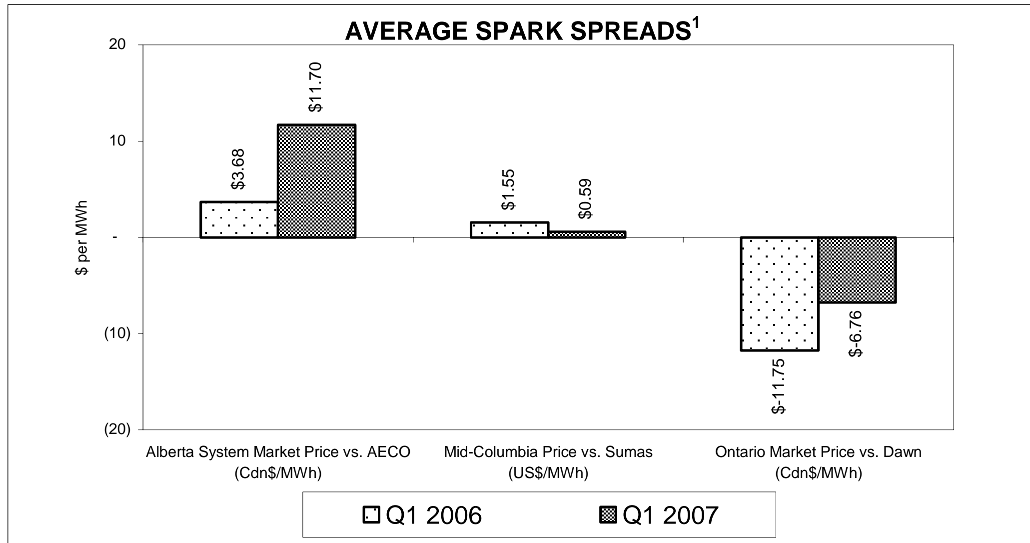
Power Purchase Agreement with New Brunswick Power

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

MARKET PRICES AND SPARK SPREADS

15 per cent of our gas fired facilities production and five per cent of our coal-fired facilities production have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.





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

For the first quarter, Mid-Columbia power prices were comparable while Ontario and Alberta spot prices increased versus the comparable period in 2006. Compared to the first quarter of 2006, spot prices increased in Alberta and Ontario due to prolonged cold weather in February. Mid-Columbia markets were also affected by the colder weather and weak hydro conditions. Spark spreads decreased in the Pacific Northwest but increased in Alberta and Ontario for the three months ended March 31, 2007 compared to the same period in 2006. Spark spreads remained negative for the past two years in Ontario for the first quarter. The effect of these prices upon the margins from our generating facilities and our trading activities are described in further detail below.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: *Owns and operates hydro, wind, geothermal, gas- and coal-fired plants and related mining operations in Canada, the U.S., and Australia. At March 31, 2007, Generation had 8,366 MW of gross generating capacity[1] in operation (7,962 MW net ownership interest) and 353 MW net under construction. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support (see the detailed discussion of the four revenue streams in our annual report for the year ended Dec. 31, 2006).*

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

The results of the Generation segment are as follows:

		2007		2006
3 months ended March 31	**Total**	**Per installed MWh[1]**	Total	Per installed MWh[1]
Revenues	**$ 671.9**	**$ 9.17**	$ 680.0	$ 9.28
Fuel and purchased power	**(290.7)**	**(3.97)**	(295.3)	(4.03)
Gross margin	**381.2**	**5.20**	384.7	5.25
Operations, maintenance and administration	**103.9**	**1.42**	104.4	1.42
Depreciation and amortization	**95.4**	**1.30**	98.1	1.34
Taxes, other than income taxes	**5.4**	**0.07**	5.5	0.08
Intersegment cost allocation	**7.1**	**0.10**	6.9	0.09
Operating expenses	**211.8**	**2.89**	214.9	2.93
Operating income	**$ 169.4**	**$ 2.31**	$ 169.8	$ 2.32
Installed capacity (GWh)[1]	**73,286**		73,286	
Production (GWh)	**12,697**		12,444	
Availability (%)	**88.2**		96.9	

[1] We have traditionally presented gross margins and other key elements of the income statement on a per MWh produced. While for specific types of contracts this is an effective measure of profitability between periods, levels of production and associated revenues and costs are not comparable across all plants within the Generation segment. To better gauge overall fleet performance and return on the investment in assets, we have presented overall results on an installed MWh, which is a measure of overall fleet capacity. We have used this measure for the first time in this quarterly report and will continue this practice going forward.

Availability

Availability for the three months ended March 31, 2007 decreased to 88.2 per cent from 96.9 per cent compared to the same period in 2006 primarily due to derating at Centralia Coal due to test burns on PRB coal, higher planned and unplanned outages at the Alberta Thermal plants and higher unplanned outages at Centralia Gas.

Production

Production for the first quarter increased 253 GWh compared to the same period in 2006 as a result of increased production at Poplar Creek (76 GWh), Fort Saskatchewan (120 GWh), Genesee 3 (28 GWh), and Sarnia (122 GWh) due to higher market and customer demand, lower planned outages at CE Gen (45 GWh), and lower unplanned outages at Meridian (25 GWh). Production increased at Ottawa (81 GWh) as during the first quarter of 2006 we curtailed production to sell gas. These increases were partially offset by higher planned and unplanned outages at Alberta Thermal (254 GWh) and lower hydro production (47 GWh).

Revenue

Revenue decreased by $8.1 million for the three months ended March 31, 2007 as compared to the same period in 2006 primarily due to higher planned and unplanned outages at Alberta Thermal ($14.8 million), lower revenue at Centralia as a result of lower power sales ($8.5 million), lower revenue from Ottawa gas sales ($6.5 million), and lower sales of emission credits at Centralia Coal ($7.2 million) partially offset by higher pricing at Centralia Coal ($6.5 million), higher production and spark spreads at Poplar Creek ($6.4 million), Genesee 3 ($3.8 million), and Sarnia ($8.4 million).

Fuel and purchased power

Fuel and purchased power decreased by $4.6 million for the three months ended March 31, 2007 compared to the same period in 2006 due to lower production at Alberta Thermal ($3.1 million), lower fuel costs at Centralia Coal ($6.7 million) and lower replacement power volumes at Centralia ($7.2 million) partially offset by higher coal costs at Alberta Thermal ($9.7 million), and increased production at Poplar Creek ($2.8 million) and Sarnia ($5.7 million).

Operations, maintenance and administration expense

For the three months ended March 31, 2007, OM&A expense was comparable to the same period in 2006 primarily due to lower planned maintenance at the Imperial Valley mostly offset by higher planned maintenance at Alberta Thermal.

Depreciation expense

For the three months ended March 31, 2007, depreciation expense decreased $2.7 million primarily due to the impairment recorded on turbines held in inventory in the first quarter of 2006 ($9.6 million) and lower depreciation at Centralia Gas ($1.2 million) partially offset by retirement of parts replaced during planned maintenance in 2007 ($1.2 million) and higher depreciation across the fleet as a result of capital spending in 2006.

Planned maintenance

The table below shows the amount of planned maintenance capitalized and expensed in the three months ended March 31, 2007 and 2006, excluding CE Gen and Mexico:

	Coal		Gas and Hydro		Total	
3 months ended March 31	**2007**	2006	**2007**	2006	**2007**	2006
Capitalized	**$ 2.8**	$ 4.9	**$ 0.3**	$ 2.6	**$ 3.1**	$ 7.5
Expensed	**4.6**	2.3	**-**	0.4	**4.6**	2.7
	$ 7.4	$ 7.2	**$ 0.3**	$ 3.0	**$ 7.7**	$ 10.2
GWh lost	**111**	4	**3**	12	**114**	16

In the three months ended March 31, 2007, production lost due to planned maintenance increased to 114 GWh from 16 GWh for the same period in 2006 primarily due to higher planned outages at Alberta Thermal.

In the three months ended March 31, 2007, total capitalized maintenance costs were $4.4 million lower than the same period in 2006 mainly due to the scope of work completed in 2006. Expensed maintenance costs are higher than the same period in 2006 mainly due to the timing of planned outages at Alberta Thermal.

Generation gross margins

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

3 months ended March 31, 2007	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & Purchased Power**	**Gross Margin**	**Revenue per installed MWh**	**Fuel & Purchased Power per installed MWh**	**Gross Margin per installed MWh**
Alberta PPAs	**6,622**	**34,348**	**$ 197.3**	**$ 67.7**	**$ 129.6**	**$ 5.74**	**$ 1.97**	**$ 3.77**
Long-term contracts	**1,846**	**9,522**	**177.0**	**102.2**	**$ 74.8**	**18.59**	**10.73**	**7.86**
Merchant	**3,579**	**26,105**	**232.8**	**102.8**	**$ 130.0**	**8.92**	**3.94**	**4.98**
CE Gen	**650**	**3,311**	**64.8**	**18.0**	**$ 46.8**	**19.57**	**5.44**	**14.13**
	12,697	**73,286**	**$ 671.9**	**$ 290.7**	**$ 381.2**	**$ 9.17**	**$ 3.97**	**$ 5.20**

3 months ended March 31, 2006	Production (GWh)	Installed (GWh)	Revenue	Fuel & Purchased Power	Gross Margin	Revenue per installed MWh	Fuel & Purchased Power per installed MWh	Gross Margin per installed MWh
Alberta PPAs	6,733	34,348	$ 208.3	$ 59.1	$ 149.2	$ 6.06	$ 1.72	$ 4.34
Long-term contracts	1,589	9,522	176.4	101.8	$ 74.6	18.53	10.70	7.83
Merchant	3,517	26,105	233.7	118.6	$ 115.1	8.95	4.54	4.41
CE Gen	605	3,311	61.6	15.8	$ 45.8	18.60	4.77	13.83
	12,444	73,286	$ 680.0	$ 295.3	$ 384.7	$ 9.28	$ 4.03	$ 5.25

Alberta PPAs

Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability and an excess energy payment for power production above committed capacity. Our Sundance, Keephills, Sheerness, and the contracted portion of the Alberta hydro assets are included in this category.

Production for the three months ended March 31, 2007 decreased by 111 GWh compared to the same period in 2006 primarily as a result of higher unplanned outages (167 GWh) partially offset by higher demand from PPA customers (71 GWh).

Revenues for the three months ended March 31, 2007 decreased by $11.0 million ($0.32 per installed MWh) compared to the same period in 2006 primarily due to higher unplanned outages and contractual penalties paid as a result of higher prices.

Fuel and replacement power costs for the three months ended March 31, 2007 increased $8.6 million ($0.25 per installed MWh) compared to the same period in 2006 mainly due to an increase in the cost of coal as a result of higher overburden removal and increased input costs ($8.9 million) partially offset by lower production ($1.4 million).

Long-term contracts

Long-term contracts typically have an original term between 10 and 25 years. Long-term contracts are typically for gas-fired cogeneration plants and have between one and four customers per plant. Revenues are derived from payments for capacity and/or the production of electrical energy and steam. The results from our Mississauga, Windsor, Wailuku, Ottawa, Fort Saskatchewan, and Meridian plants as well as the contracted portions of Sarnia, Poplar Creek, and TransAlta Wind are included in this category.

Production for the three months ended March 31, 2007 increased 257 GWh compared to the same period in 2006 due to increased customer demand at Fort Saskatchewan (120 GWh), and Poplar Creek (16 GWh), lower unplanned outages at Meridian (25 GWh), and increased production at Ottawa (81 GWh).

For the three months ended March 31, 2007, gross margins remained consistent ($0.03 per installed MWh) compared to the same period in 2006 as increased thermal production at Sarnia ($3.6 million) as well as increased production at Poplar Creek ($1.1 million) and Meridian ($1.3 million) was mostly offset by lower gas sales at Ottawa ($6.5 million).

Merchant

Merchant revenue is derived from production and is sold via: medium-term contract sales (typically two to ten years), short-term asset-backed trading, and spot or short-term (less than one year) forward markets. The results from Centralia Coal, Centralia Gas, Genesee 3, Wabamun, Binghamton, excess energy sales from Sundance, Keephills, Hydro, and Sheerness, and uncontracted portions of TransAlta Wind, Poplar Creek, and Sarnia are included in this category.

In the first quarter of 2007, merchant production was 3,579 GWh, of which 969 GWh was contracted under medium-term contracts, compared to the first quarter of 2006, where merchant production was 3,517 GWh, of which 1,139 GWh was contracted. The increase in total production of 62 GWh was primarily due to higher market demand at Sarnia (115 GWh), Poplar Creek (59 GWh), and Genesee 3 (28 GWh) partially offset by increased planned outages at Alberta Thermal (103 GWh) and lower hydro production (47 GWh).

For the three months ended March 31, 2007, gross margins increased $14.9 million ($0.57 per installed MWh) compared to the same period in 2006 due to favourable production and spark spreads at Poplar Creek ($2.7 million) and Genesee 3 ($3.8 million), favourable pricing at the Alberta Thermal plants ($5.8 million) and Centralia Coal ($6.5 million), and lower coal costs at Centralia ($6.7 million) partially offset by higher planned outages at Alberta Thermal plants ($4.0 million) and the sale of emission credits at Centralia Coal in 2006 ($7.2 million).

CE Gen

Our share of CE Gen production for the three months ended March 31, 2007, increased 45 GWh compared to the same period in 2006 primarily due to lower planned and unplanned outages at Imperial Valley and the Yuma and Power Resources gas plants.

For the three months ended March 31, 2007, gross margins increased $1.0 million ($0.30 per installed MWh) compared to the same period in 2006 from higher pricing at Saranac and higher overall production.

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

Our Energy Trading activities utilize a variety of instruments to manage risk, earn trading revenue and gain market information. Our trading

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

While trading products are generally consistent between periods, positions held and resulting earnings impacts will vary due to current and forecasted external market conditions. Positions for each region are established based on the market conditions and the risk reward ratio established for each trade at the time they are transacted. Results, therefore, are generally not consistent regionally or by strategy from one reported period to the next.

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

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

	3 months ended March 31	
	2007	2006
Revenues	**$ 51.8**	$ 53.7
Trading purchases	**(41.3)**	(44.4)
Gross margin	**10.5**	9.3
Operations, maintenance and administration	**8.6**	8.1
Depreciation and amortization	**0.4**	0.3
Intersegment cost allocation	**(7.1)**	(6.9)
Operating expenses	**1.9**	1.5
Operating income	**$ 8.6**	$ 7.8

For the first quarter of 2007 relative to the same period in 2006, gross margin increased $1.2 million. The western region market positions held have reacted favorably to early season hydro conditions. Eastern region results were lower than 2006 due to reduced electricity trading but still had a positive contribution.

OM&A costs increased $0.5 million for the three months ended March 31, 2007 compared to the same period in 2006. Increased staff compensation was partially offset by lower contracted manpower costs.

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

NET INTEREST EXPENSE

3 months ended March 31	**2007**	2006
Interest on long-term debt	**$ 38.8**	$ 34.1
Interest on short-term debt	**6.5**	3.7
Interest on preferred securities	**-**	3.4
Interest income	**(7.7)**	(0.7)
Capitalized interest	**(0.3)**	-
Net interest expense	**$ 37.3**	$ 40.5

For the three months ended March 31, 2007, net interest expense was $3.2 million lower than the comparable period in 2006 due to lower long-term debt levels partially offset by an interest gain on the unwind of a net investment hedge recorded in 2006 ($6.0 million). Net interest expense was also reduced due to the redemption of preferred securities ($3.4 million) and higher interest income from cash deposits ($6.8 million) partially offset by higher short-term debt balances ($2.8 million).

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests in the three months ended March 31, 2007 at $2.9 million was lower than the same period in 2006 due to lower earnings at TA Cogen as a result of lower margins at Ottawa.

EQUITY LOSS

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

	3 months ended March 31	
	2007	2006
Availability (%)	**96.9**	91.2
Production (GWh)	**579**	612
Equity loss	**$ (8.9)**	$ (1.0)
Capital expenses	**-**	2.0
Operating cash flow	**(2.2)**	(0.5)
Interest expense	**9.9**	8.3

Availability increased for the three months ended March 31, 2007 as a result of lower planned outages at the Chihuahua plant. Production decreased for the same period as a result of lower customer demand at the Campeche plant partially offset by increased production at the Chihuahua plant, primarily due to lower planned outages.

For the three months ended March 31, 2007, equity loss increased due to lower margins ($1.9 million), timing of routine maintenance and other operating expenses ($2.6 million), increased depreciation as a result of capital spending on planned maintenance in 2006 ($1.6 million), and increased interest costs as a result of refinancing these subsidiaries in 2006 ($8.8 million) partially offset by the recognition of deferred financing fees in 2006 ($7.2 million).

INCOME TAXES

	3 months ended March 31	
	2007	2006
Earnings before income taxes	**$ 90.0**	$ 93.0
Turbine impairment	**-**	9.6
Earnings before income taxes and turbine impairment	**$ 90.0**	$ 102.6
Income tax expense per financial statements	**24.0**	23.8
Net income	**$ 66.0**	$ 69.2
Effective tax rate (%)	**26.7**	23.2

Tax expense was comparable in the three months ended March 31, 2007 to the same period in 2006 due to the reduction in the pre-tax earnings offset by the effect of the change in the mix of jurisdictions in which pre-tax income is earned.

FINANCIAL POSITION

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

3 months ended March 31	Increase/ (Decrease)	Explanation
Cash and cash equivalents	$ 12.9	Refer to Consolidated Statements of Cash Flows
Accounts receivable	(210.7)	Timing of collections of November 2006 revenues
Prepaid expenses	17.4	Insurance premiums and other prepaids
Risk management assets (current)	(2.1)	Adoption of new accounting standards on financial instruments
Inventory	(14.3)	Lower inventory balances at Centralia Coal
Investments	(17.3)	Net loss and debt repayments by equity subsidiaries and effect of change in exchange rates
Property, plant and equipment, net	(47.4)	Depreciation expense partially offset by capital additions and weakening of the Canadian dollar compared to the U.S. dollar
Intangible assets	(10.3)	Amortization expense partially offset by the weakening of the Canadian dollar compared to the U.S. dollar
Risk management assets (long-term)	(14.5)	As a result of adopting new accounting standards on financial instruments
Other assets (including current portion)	2.1	Realized gain on settlement of net investment hedges and mark-to-market changes on hedging derivatives and reclassification of certain treasury price risk management assets
Accounts payable and accrued liabilities	(77.3)	Timing of major maintenance activities offset by increased CD&M activities
Risk management liabilities (current)	105.5	As a result of adopting new accounting standards on financial instruments
Preferred securities	(175.0)	Repaid in January 2007
Deferred credits and other long-term liabilities (including current portion)	(18.1)	Normal accretion expense less ARO liabilities settled and payment of Centralia mine closure costs
Risk management liabilities (long-term)	270.8	As a result of adopting new accounting standards on financial instruments
Net future income tax liabilities (including current portions)	(132.7)	Tax effect of adjustments related to new accounting standards on financial instruments
Shareholders' equity	(239.9)	Net earnings for the period and dividends offset by dividend reinvestment program and share issuances and adoption of new accounting standards

FINANCIAL INSTRUMENTS

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

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

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

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

reclassified as the opening balance of AOCI.

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

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

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

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

See Notes 1, 2, and 3 in the interim financial statements for more detailed discussion and analysis in the adoption of these new standards.

RISK MANAGEMENT ASSETS AND LIABILITIES

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

Energy Trading

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

The following tables show the balance sheet classifications for risk management assets and liabilities for energy trading activities and the changes in the fair value for the period, separately by source of valuation:

Balance Sheet	March 31, 2007			Dec. 31, 2006
	Hedges	Non-Hedges	Total	Total related to energy trading
Risk management assets				
- Current	$ 0.7	$ 43.8	$ 44.5	$ 61.0
- Long-term	(0.9)	4.1	3.2	21.9
Risk management liabilities				
- Current	(118.5)	(17.6)	(136.1)	(30.3)
- Long-term	(273.3)	14.3	(259.0)	(1.0)
Net risk management assets (liabilities) outstanding	$ (392.0)	$ 44.6	$ (347.4)	$ 51.6

As a result of adopting new accounting standards on financial instruments risk management assets and liabilities receiving hedge accounting were recorded at fair value. The impact upon previously reported values is shown below along with changes in those values during Q1 2007:

	Hedges		Non-Hedges		
Change in fair value of net assets (liabilities)	Mark to Market	Mark to Model	Mark to Market	Mark to Model	Total
Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	$ 51.6
Net risk management assets outstanding at Dec. 31, 2006 - *fair value (Note 1)*	(253.0)	(19.8)	52.7	(1.1)	(221.2)
Contracts realized, amortized or settled during the period	5.9	1.4	(13.5)	(0.4)	(6.6)
Changes in values attributable to market price and other market changes	(118.0)	(7.2)	3.2	(0.2)	(122.2)
New contracts entered into during the current calendar year	(4.8)	-	3.3	4.1	2.6
Changes in values attributable to discontinued hedge treatment of certain contracts	3.5	-	(3.5)	-	-
Net risk management assets (liabilities) outstanding at March 31, 2007	$ (366.4)	$ (25.6)	$ 42.2	$ 2.4	$ (347.4)

For the three months ended March 31, 2007, the fair value of our net risk management assets and liabilities associated with non-hedge positions decreased $7.0 million compared to Dec. 31, 2006 primarily due to contracts settled during the quarter partially offset by new contracts entered in 2007 and value changes associated with contracts in existence at both period ends. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of both the CD&M and the Generation business segments.

For the three months ended March 31, 2007, the fair value of our net risk management assets and liabilities associated with hedge positions decreased $119.2 million compared to Dec. 31, 2006 primarily due to value changes associated with contracts in existence at both period ends. Changes in net risk management assets and liabilities for hedge positions are reflected within the gross margin of both the CD&M and the Generation business segments to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until the delivery date of the underlying product and contract settlement occurs.

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

		2007	2008	2009	2010	2011	2012 and thereafter	Total
Hedges	Prices actively quoted	$ (80.9)	$ (129.5)	$ (99.8)	$ (49.7)	$ (4.8)	$ (1.7)	$ (366.4)
	Prices based on models	(3.5)	(6.5)	(6.7)	(6.4)	(2.5)	-	$ (25.6)
		$ (84.4)	$ (136.0)	$ (106.5)	$ (56.1)	$ (7.3)	$ (1.7)	$ (392.0)
Non-Hedges	Prices actively quoted	$ 42.7	$ (0.8)	$ 0.3	$ -	$ -	$ -	$ 42.2
	Prices based on models	1.1	1.1	0.2	-	-	-	$ 2.4
		$ 43.8	$ 0.3	$ 0.5	$ -	$ -	$ -	$ 44.6
Grand total		$ (40.6)	$ (135.7)	$ (106.0)	$ (56.1)	$ (7.3)	$ (1.7)	$ (347.4)

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

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

transactions.

Other Risk Management Assets and Liabilities

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

The impact upon previously reported values is shown below along with changes in those values during the first quarter of 2007:

Balance Sheet	March 31, 2007			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to non-energy trading
Risk management assets				
- Current	**$ 25.6**	**$ -**	**$ 25.6**	$ 11.2
- Long-term	**47.4**	**-**	**$ 47.4**	43.2
Risk management liabilities				
- Current	**(1.8)**	**-**	**$ (1.8)**	(2.1)
- Long-term	**(11.4)**	**(14.4)**	**$ (25.8)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 59.8**	**$ (14.4)**	**$ 45.4**	$ 39.3

As a result of adopting new accounting standards on financial instruments risk management assets and liabilities receiving hedge accounting were recorded at fair value. The impact upon previously reported values is shown below along with changes in those values during Q1 2007:

	Hedges	**Non-Hedges**	**Total**
Net Other Risk Management Assets (Liabilities) at Dec. 31, 2006 - *as reported*	50.1	(10.8)	39.3
Net Other Risk Management Assets (Liabilities) at Dec. 31, 2006 - *fair value*	58.0	(10.3)	47.7
Changes in values attributable to realization of contracts- (gains)/losses	3.4	(0.3)	3.1
Unrealized changes attributable to market price and other market changes -gains/(losses)	(2.7)	(3.8)	(6.5)
Unrealized new contracts entered into during the current calendar year - gains/losses	1.1	-	1.1
Net Other Risk Management Assets (Liabilities) at March 31, 2007 - *fair value*	59.8	(14.4)	45.4

For the three months ended March 31, 2007, the fair value of our net risk management assets and liabilities associated with non-hedge positions decreased $4.1 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for non-hedge positions are reflected within interest expense.

For the three months ended March 31, 2007, the fair value of our net risk management assets and liabilities associated with hedge positions increased $1.8 million compared to Dec. 31, 2006 primarily due to value changes in new contracts entered into during the period. Realization of gains on contracts was mostly offset by unrealized changes in market values. Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument, change in ownership of the foreign operation, or financial instrument being hedged.

Total Balances

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

Balance Sheet	March 31, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	44.5	25.6	70.1	61.0	11.2	72.2
- Long-term	3.2	47.4	50.6	21.9	43.2	65.1
Risk management liabilities						
- Current	(136.1)	(1.8)	(137.9)	(30.3)	(2.1)	(32.4)
- Long-term	(259.0)	(25.8)	(284.8)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	(347.4)	45.4	(302.0)	51.6	39.3	90.9

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

STATEMENTS OF CASH FLOWS

3 months ended March 31	2007	2006	Explanation
Cash and cash equivalents, beginning of period	**$ 65.6**	$ 79.3	
Provided by (used in):			
Operating activities	**330.8**	200.7	Increase in inflows was due to $185 million in receivables relating to 2006 were collected in the quarter partially offset by a decrease in cash earnings and payment of $23.0 of Centralia mine closure costs.
Investing activities	**(55.0)**	(11.9)	In 2007 cash outflows were primarily due to additions to property, plant and equipment of $54.3 million. In 2006, cash outflows were primarily due to additions of property, plant and equipment of $29.2 million partially offset by unrealized gains from unwinding net investment hedges of $18.7 million.
Financing activities	**(262.7)**	(177.3)	In 2007, cash outflows were due to a decrease in short-term debt of $7.1 million and dividends on common shares of $54.2 million, preferred securities of $175.0 million and non-controlling interests of $20.8 million In 2006, cash outflows were due to repayment of long-term debt of $259.6 million, distributions to subsidiaries' non-controlling interests of $17.2 million, dividends on common shares of $32.9 million partially offset by an increase in short-term debt $125.5 million.
Cash and cash equivalents, end of period	**$ 78.5**	$ 89.9	

Operating activities

For the three months ended March 31, 2007, funds generated from operations increased to $330.8 million from $200.7 million for the same period in 2006 due to the timing of collection of 2006 receivables amounting to $185 million. These accounts receivable balances in respect of November 2006 revenues were contractually scheduled to be paid, and were received, on Jan. 2, 2007. This increase in cash flow in the current quarter was partially offset by lower cash earnings. In the first quarter, the Corporation paid $23.0 million of costs related to the closure of the Centralia coal mine.

Investing activities

For the three months ended March 31, 2007, cash used in investing activities was $55.0 million compared to $11.9 million of cash used for the same period in 2006. The increase in cash used was mainly due to higher capital expenditures and the realization of gains on settling net investment hedges in 2006.

For the three months ended March 31, 2007, the corporation realized no cash outflows from the settlement of net investment hedges of foreign subsidiaries compared to cash inflows of $18.7 million for the same period in 2006.

In 2007, the corporation has incurred a total of $13.0 million in capital expenditures relating to the Kent Hills, Sundance unit 4 uprate, and Keephills 3 projects.

Financing activities

For the three months ended March 31, 2007, cash used in financing activities was $262.7 million compared to $177.3 million for the same quarter of 2006. This increase in cash used was mainly due to increased cash dividends paid on common shares and timing of those payments of $21.3 million and the repayment of preferred securities of $175.0 million. $7.1 million of short-term debt was repaid in the current quarter versus an increase of short-term debt of $125.5 million during the same period in 2006.

LIQUIDITY AND CAPITAL RESOURCES

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

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

We have a $1.5 billion committed syndicated credit facility and approximately $0.4 billion of uncommitted credit facilities. At March 31, 2007, we had $0.9 billion available under these credit facilities (Dec. 31, 2006 - $0.8 billion).

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 March 31, 2007, we had issued letters of credit totaling $632.0 million compared to $633.2 million at Dec. 31, 2006.

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

On April 23, 2007, we had approximately 202.7 million common shares outstanding.

Guarantee contracts

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. To the extent liabilities related to these guaranteed contracts exist, they are included in the consolidated balance sheet. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at March 31, 2007 was a maximum of $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at March 31, 2007, under the limited and unlimited guarantees, was $253.0 million as compared to $285.3 million at Dec. 31, 2006.

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at March 31, 2007 was a maximum of $1.1 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at March 31, 2007, they are included in accounts payable and accrued liabilities.

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

OUTLOOK

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

Production, availability and capacity

Generating capacity is expected to increase slightly due to the completion of an uprate at Unit 4 of our Sundance coal-fired facility in the latter portion of third quarter of 2007. Production and availability is expected to decrease in the second quarter due to higher planned

outages. Production in the third and fourth quarters are expected to slightly increase compared to the first quarter.

Power prices

Despite strong year over year demand growth and marginal supply additions in Alberta, electricity prices and spark spreads for the remainder of 2007 are anticipated to be lower than those observed in 2006 due to an expectation of a return to normal unit outage rates and normal weather conditions. Compared to 2006 minimal load growth is expected in the Pacific Northwest but stronger natural gas prices are expected to keep power prices and spark spreads higher for the rest of 2007. Ontario prices are also expected to strengthen compared to 2006 with an expectation of stronger natural gas prices.

15 per cent of our gas fired facilities production and five per cent of our coal-fired facilities production have exposure to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Fuel costs

Mining coal is subject to cost increases due to increased overburden removal, inflation, and diesel commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Coal costs in Alberta for 2007 are expected to be $30 million higher than those seen in 2006. Fuel at Centralia Coal is purchased from an external supplier and costs are expected to be comparable with those seen in the first quarter.

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

Operations, maintenance and administration costs

OM&A costs per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per MWh of installed capacity are anticipated to be higher in the second and third quarters due to higher planned maintenance.

Capital expenditures

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

Sustaining expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructures, as well as investments in our mines. For 2007, our estimate for total sustaining capital expenditures, excluding Mexico, is between $320 million and $345 million, allocated among:

- $100 - $105 million for routine capital,
- $80 - $85 million for mining equipment,
- $55 - $60 million for equipment modifications at Centralia Coal and
- $85 - $95 million on planned maintenance as outlined in the following table:

	Coal	Gas and Hydro	Total
Capitalized	$70-75	$15-20	$85-95
Expensed	65-70	0-5	65-75
	$135-145	$15-25	$150-170
GWh lost	2,000-2,050	125-150	2,125-2,200

In 2007, we expect to lose approximately 2,125 to 2,200 GWh of production due to planned maintenance. During 2007, we have no significant planned maintenance activities at our Mexican operations.

Growth expenditures

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

Energy trading

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

Exposure to fluctuations in foreign currencies

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

Net interest expense

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

Liquidity and capital resources

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

Environmental legislation

On March 8, 2007 the Province of Alberta announced its proposed climate change legislation and regulations. The Alberta plan imposes a requirement of a 12 per cent Greenhouse Gas (“GHG”) emission intensity reduction on major emitters commencing on July 1, 2007. Compliance can be achieved through direct emission reductions, payment into a Technology Fund at a fixed price, or through the purchase of offset credits from other projects within Alberta.

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

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

The Canadian Government is expected to release the details of its clean air plans in April of 2007. The interaction of the Alberta and Canadian Government legislation remains to be determined but we expect some form of harmonization between the two.

On April 12, 2007, Washington State passed Bill 6001 designed to address climate change. The legislation sets out performance goals for new, long-term electricity contracts undertaken by State utilities. It also paves the way for development of specific regulations for the industrial and transportation sectors, which will be developed through consultation over the next year. At this stage it is not clear if the future regulations will affect TransAlta's baseload generation. There is provision for exemption from the performance standards for system reliability or financial reasons. TransAlta will be participating in the consultation process to develop the regulations. There are also several federal U.S. climate bills under consideration in the House and Senate. Should one of these pass into law, then we would expect some form of harmonization between the federal and the State legislation.

NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under GAAP and therefore should not be considered in isolation or as an alternative to or more meaningful than, net income or cash

flow from operating activities as determined in accordance with GAAP as an indicator of the corporation's financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

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

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

3 months ended March 31		**2007**		2006
Gross margin	**$**	**391.7**	$	394.0
Operating expenses		**(239.6)**		(240.0)
Operating income		**152.1**		154.0
Foreign exchange loss (gain)		**0.1**		(0.6)
Net interest expense		**(37.3)**		(40.5)
Equity loss		**(8.9)**		(1.0)
Earnings before non-controlling interests and income taxes		**106.0**		111.9
Non-controlling interests		**16.0**		18.9
Earnings before income taxes		**90.0**		93.0
Income tax expense		**24.0**		23.8
Net earnings	**$**	**66.0**	$	69.2

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Because we believe the turbine impairment charge recorded in the first quarter of 2006 would otherwise affect the comparability of our results from period to period, we have excluded that item to calculate earnings on a comparable basis.

3 months ended March 31		**2007**		2006
Earnings on a comparable basis	**$**	**66.0**	$	75.4
Turbine impairment, net of tax		**-**		(6.2)
Net earnings	**$**	**66.0**	$	69.2
Weighted average common shares outstanding in the period		**202.6**		199.5
Earnings on a comparable basis per share	**$**	**0.33**	$	0.38

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

The contractually scheduled payments from 2006 have been excluded from the calculation of free cash flow as the timing of this payment is dependant upon certain calendar holidays in the month of December and this change due to timing does not occur on a frequent basis. The payment of Centralia mine closure costs have also been excluded as they are one-time in nature. Sustaining capital expenditures is total capital expenditures per the statement of cash flow less $13.0 million we have invested in growth projects in the first quarter of 2007. There were no investments in growth projects in the first quarter of 2006.

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

	3 months ended March 31	
	2007	2006
Cash flow from operating activities	**$ 330.8**	$ 200.7
Add (Deduct):		
Sustaining capital expenditures	**(41.3)**	(29.2)
Dividends on common shares	**(54.2)**	(32.9)
Distribution to subsidiaries' non-controlling interest	**(20.8)**	(17.2)
Non-recourse debt repayments	**(8.7)**	(4.5)
Timing of contractualy scheduled payments from 2006	**(185.0)**	-
Centralia closure costs	**23.0**	-
Cash flows from equity investments	**(2.2)**	(2.5)
Free cash flow	**$ 41.6**	$ 114.4

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

SELECTED QUARTERLY INFORMATION

(In millions of Canadian dollars except per share amounts)

2006 Quarters	**Q2 2006**	**Q3 2006**	**Q4 2006**	**Q1 2007**
Revenue	**$ 599.0**	**$ 684.0**	**$ 779.8**	**$ 723.7**
Earnings (loss) from continuing operations	**86.4**	**35.3**	**(146.0)**	**66.0**
Net earnings (loss)	**86.0**	**35.3**	**(146.0)**	**66.0**
Basic earnings (loss) per common share:				
Continuing operations	**0.43**	**0.18**	**(0.72)**	**0.33**
Net earnings (loss)	**0.43**	**0.18**	**(0.72)**	**0.33**
Diluted earnings (loss) per common share:				
Continuing operations	**0.43**	**0.18**	**(0.72)**	**0.33**
Net earnings (loss)	**0.43**	**0.18**	**(0.72)**	**0.33**

2005 Quarters	**Q2 2005**	**Q3 2005**	**Q4 2005**	**Q1 2006**
Revenue	$ 621.2	$ 722.9	$ 810.1	$ 733.7
Earnings from continuing operations	25.8	51.2	47.9	69.2
Net earnings	25.8	51.2	59.9	69.2
Basic earnings per common share:				
Continuing operations	0.13	0.26	0.24	0.35
Net earnings	0.13	0.26	0.30	0.35
Diluted earnings per common share:				
Continuing operations	0.13	0.26	0.24	0.35
Net earnings	0.13	0.26	0.30	0.35

CONTROLS AND PROCEDURES

As of the end of the period covered by this quarterly report, TransAlta's management, together with TransAlta's President and Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the company's disclosure controls and procedures. Based on this evaluation, the President and Chief Executive Officer and Chief Financial Officer have concluded that the disclosure controls and procedures of the company are effective. These certificates can be found at www.sedar.com.

TransAlta's internal control over financial reporting changed during the current quarter as a result of adopting new accounting standards for

financial instruments and comprehensive income. These changes affected our accounting processes and as a result we updated our internal controls. Changes to our accounting system were facilitated through our existing information technology controls and processes.

TransAlta is currently in the testing phase of an enhancement to its accounting system and associated processes which will be used to prepare the second quarter results. Changes to our accounting system will be facilitated through our existing controls and processes.

FORWARD-LOOKING STATEMENTS

This MD&A and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on TransAlta Corporation's beliefs and assumptions based on information available at the time the assumption was made. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. The forward-looking statements relate to, among other things, statements regarding the anticipated business prospects and financial performance of TransAlta. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties and other important factors that could cause the corporation's actual performance to be materially different from those projected, including those material risks discussed in this MD&A under the heading 'Outlook' and in the MD&A in our annual report for the year ended Dec. 31, 2006 under the heading 'Risk Factors and Risk Management'. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs, 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)

Unaudited	3 months ended March 31 2007	2006
Revenues	**$ 723.7**	$ 733.7
Trading purchases	**(41.3)**	(44.4)
Fuel and purchased power	**(290.7)**	(295.3)
Gross margin	**391.7**	394.0
Operations, maintenance and administration	**135.1**	133.0
Depreciation and amortization	**99.0**	101.5
Taxes, other than income taxes	**5.5**	5.5
Operating expenses	**239.6**	240.0
Operating income	**152.1**	154.0
Foreign exchange gain (loss)	**0.1**	(0.6)
Net interest expense *(Note 5)*	**(37.3)**	(40.5)
Equity loss	**(8.9)**	(1.0)
Earnings before income taxes and non-controlling interests	**106.0**	111.9
Non-controlling interests	**16.0**	18.9
Earnings before income taxes	**90.0**	93.0
Income tax expense	**24.0**	23.8
Net earnings	**66.0**	69.2
Common share dividends	**(50.7)**	(49.9)
Retained earnings		
Opening balance	**710.0**	868.2
Closing balance	**$ 725.3**	$ 887.5
Weighted average common shares outstanding in the period	**202.6**	199.5
Net earnings per share, basic and diluted	**$ 0.33**	$ 0.35

TRANSALTA CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE LOSS

(in millions of Canadian dollars)

3 months ended March 31	
Net earnings	**$ 66.0**
Other comprehensive income, net of tax *(Note 2)*	
Gains on translating net assets of self-sustaining foreign operations	1.3
Losses on financial instruments designated as hedges of self-sustaining foreign operations	(3.3)
Losses on translation of self-sustaining foreign operations	(2.0)
Losses on derivatives designated as cash flow hedges	(86.7)
Gains on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period	5.5
Other comprehensive loss, net of tax	(83.2)
Comprehensive loss	**$ (17.2)**

See accompanying notes

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

Unaudited	March 31 2007	Dec. 31 2006
ASSETS		*(Restated, Note 1)*
Current assets		
Cash and cash equivalents	**$ 78.5**	$ 65.6
Accounts receivable	**407.6**	618.3
Prepaid expenses	**26.5**	9.1
Risk management assets *(Notes 1 and 3)*	**70.1**	72.2
Future income tax assets	**55.4**	25.8
Income taxes receivable	**48.5**	47.6
Inventory	**38.7**	53.0
Current portion of other assets *(Note 1)*	**-**	5.4
	725.3	897.0
Restricted cash *(Note 13)*	**339.8**	347.8
Investments	**137.2**	154.5
Long-term receivables	**31.2**	32.2
Property, plant and equipment		
Cost	**8,642.1**	8,588.0
Accumulated depreciation	**(3,647.6)**	(3,546.1)
	4,994.5	5,041.9
Assets held for sale, net *(Note 6)*	**110.1**	109.8
Goodwill	**137.7**	137.5
Intangible assets	**281.8**	292.1
Future income tax assets	**349.0**	294.0
Risk management assets *(Notes 1 and 3)*	**50.6**	65.1
Other assets *(Notes 1 and 4)*	**95.7**	88.2
Total assets	**$ 7,252.9**	$ 7,460.1
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt *(Note 3)*	**$ 349.2**	$ 361.9
Accounts payable and accrued liabilities	**364.6**	441.9
Risk management liabilities *(Note 3)*	**137.9**	32.4
Income taxes payable	**20.8**	22.3
Future income tax liabilities	**19.8**	19.9
Dividends payable	**47.9**	51.5
Deferred credits and other current liabilities *(Notes 1 and 7)*	**46.5**	48.5
Current portion of long-term debt - recourse *(Note 5)*	**204.6**	205.0
Current portion of long-term debt - non-recourse *(Note 5)*	**45.5**	44.7
Preferred securities *(Note 4)*	**-**	175.0
	1,236.8	1,403.1
Long-term debt - recourse *(Note 5)*	**1,687.8**	1,681.5
Long-term debt - non-recourse *(Note 5)*	**280.4**	289.6
Deferred credits and other long-term liabilities *(Notes 1 and 7)*	**394.3**	410.4
Future income tax liabilities	**650.6**	698.6
Risk management liabilities *(Note 3)*	**284.8**	14.0
Non-controlling interests	**530.2**	535.0
Common shares *(Note 10)*	**1,787.7**	1,782.4
Retained earnings	**725.3**	710.0
Accumulated other comprehensive loss *(Note 2)*	**(325.0)**	(64.5)
	2,188.0	2,427.9
Total liabilities and shareholders' equity	**$ 7,252.9**	$ 7,460.1

Contingencies *(Notes 11 and 12)*
Commitments *(Notes 4 and 13)*

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2007**	2006
Operating activities		
Net earnings	**$ 66.0**	$ 69.2
Depreciation and amortization *(Note 8)*	**99.9**	110.3
Non-controlling interests	**16.0**	18.9
Asset retirement obligation accretion *(Note 7)*	**6.0**	5.0
Future income taxes	**(3.2)**	1.3
Asset retirement obligation costs settled *(Note 7)*	**(3.2)**	(0.8)
Unrealized losses from risk management activities	**5.0**	11.4
Foreign exchange (gain) loss	**(0.1)**	0.6
Equity loss	**8.9**	1.0
Other non-cash items	**2.8**	0.5
	198.1	217.4
Change in non-cash operating working capital balances	**132.7**	(16.7)
Cash flow from operating activities	**330.8**	200.7
Investing activities		
Additions to property, plant and equipment	**(54.3)**	(29.2)
Equity investment	**(10.0)**	(0.3)
Restricted cash	**9.4**	(0.3)
Acquisition of Wailuku Hydro facility	**-**	(1.2)
Realized foreign exchange gain on net investments	**-**	18.7
Other	**(0.1)**	0.4
Cash flow used in investing activities	**(55.0)**	(11.9)
Financing activities		
(Decrease) / Increase in short-term debt	**(7.1)**	125.5
Repayment of long-term debt *(Note 5)*	**(11.7)**	(259.6)
Dividends paid on common shares	**(54.2)**	(32.9)
Redemption of preferred securities *(Note 5)*	**(175.0)**	-
Net proceeds on issuance of common shares *(Note 10)*	**4.7**	2.6
Distributions to subsidiaries' non-controlling interests	**(20.8)**	(17.2)
Reduction in advance to TransAlta Power	**1.4**	4.3
Cash flow used in financing activities	**(262.7)**	(177.3)
Cash flow from operating, investing and financing activities	**13.1**	11.5
Effect of translation on foreign currency cash	**(0.2)**	(0.9)
Increase in cash and cash equivalents	**12.9**	10.6
Cash and cash equivalents, beginning of period	**65.6**	79.3
Cash and cash equivalents, end of period	**$ 78.5**	$ 89.9
Cash taxes paid	**$ 21.9**	$ 23.1
Cash interest paid	**$ 25.9**	$ 34.7

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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

1. ACCOUNTING POLICIES

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

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

TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically increased in the second quarter due to increased hydro production resulting from spring run-off and rainfall in the Canadian and U.S. markets.

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

Significant Accounting Policy Changes

Financial Instruments

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

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

Comprehensive Income

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

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

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

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

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

Financial Instruments – Recognition and Measurement

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

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

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

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

are managed and evaluated on a fair value basis in accordance with our risk management strategy, and are reported to senior management personnel on that basis; or (iii) it is a derivative in a financial asset or financial liability and the derivative is not closely related to the host contract.

Our financial assets and liabilities designated as held-for-trading are primarily related to our energy trading segment. Financial assets and liabilities, held to maturity, are primarily related to hedges of our self-sustaining foreign operations.

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

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

Hedges

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

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

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

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

Impact upon adoption of Sections 1530, 3855 and 3865

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

For hedging relationships existing prior to adopting Section 3865 that continue to qualify for hedge accounting under the new standard,

the transition accounting is as follows: (i) Fair value hedges – any gain or loss on the hedging instrument was recognized in opening retained earnings and the carrying amount of the hedged item was adjusted by the cumulative change in fair value attributable to the designated hedged risk and was also included in opening retained earnings; (ii) Cash flow hedges and hedges of net investments in self-sustaining foreign operations – the effective cumulative portion of any gain or loss on the hedging instrument was recognized in AOCI and the cumulative ineffective portion was included in opening retained earnings (see Note 2).

We have recorded the following transition adjustments in our consolidated financial statements: recognition in AOCI of $177.3 million, net of taxes, related to the net losses for available-for-sale financial assets and cumulative losses on the effective portion of our cash flow hedges that are now required to be recognized under Sections 3855 and 3865. In addition, we have reclassified to AOCI, $64.5 million of net foreign currency gains that were previously presented as a separate item in shareholders' equity.

Variable Interest Entities ("VIEs")

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

Future accounting changes

Capital Disclosures and Financial Instruments – Disclosures and Presentation

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

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

2. SHAREHOLDER'S EQUITY

Consolidated Statement of Comprehensive Loss
(in millions of Canadian dollars)
3 months ended March 31

Other comprehensive income	**Pre-tax**	**Net of tax**
Gains on translating net assets of self-sustaining foreign operations	1.8	1.3
Losses on financial instruments designated as hedges of self-sustaining foreign operations	(3.3)	(3.3)
Losses on translation of self-sustaining foreign operations	(1.5)	(2.0)
Losses on derivatives designated as cash flow hedges	(126.5)	(86.7)
Gains on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period	7.3	5.5
Other comprehensive loss	(120.7)	(83.2)
Comprehensive loss	**$ (120.7)**	**$ (83.2)**

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

	Common shares	Retained earnings	Accumulated other comprehensive income	Total shareholders equity
Balance, Dec. 31, 2006 *(Note 1)*	1,782.4	710.0	(64.5)	2,427.9
Change in accounting policy (*Note 1*)	-	-	(177.3)	(177.3)
Balance, Dec. 31, 2006, as adjusted	1,782.4	710.0	(241.8)	2,250.6
Net income for the 3 months ended March 31, 2007		66.0	-	66.0
Common shares issued (dividends declared)	5.3	(50.7)	-	(45.4)
Unrealized gains and losses on translating financial statements of self-sustaining foreign operations			(2.0)	(2.0)
Gains and losses on derivatives designated as cash flow hedges			(86.7)	(86.7)
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period			5.5	5.5
Balance, March 31, 2007	**$ 1,787.7**	**$ 725.3**	**$ (325.0)**	**$ 2,188.0**

3. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to prices in active markets for that instrument to which we have access. In the absence of an active market, we determine fair values based on valuation models, such as option pricing models and discounted cash flow analysis, using observable market-based inputs.

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

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

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

Carrying value and Fair value of selected Financial Instruments

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

Carrying value and fair value of financial instruments as at March 31, 2007

	Classified as held-for-trading	Designated as held-to-maturity *(Note 1)*	Per Consolidated Balance Sheet	Total Fair Value
Risk management assets				
- Short Term	70.1	-	70.1	70.1
- Long Term	50.6	-	50.6	50.6
Total risk management assets	120.7	-	120.7	120.7
Short term debt	-	349.2	349.2	349.2
Risk management liabilities				
- Short Term	137.9	-	137.9	137.9
- Long Term	284.7	-	284.8	284.8
Total price risk management liabilities	422.6	-	422.7	422.7
Debt				
- Current portion of long-term debt recourse	-	204.6	204.6	204.6
- Current portion of long-term debt non-recourse	-	45.5	45.5	45.5
- Long-term debt recourse	-	1,687.8	1,687.8	1,687.8
- Long-term debt non-recourse	-	280.4	280.4	280.4
Total debt	-	2,218.3	2,218.3	2,218.3

Note 1: Fair value option permitted as per Section 3855

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

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

	Classified as held-for-trading	Designated as held-to-maturity	Total Carrying Value	Per Consolidated Balance Sheet	Total Fair Value [2]
Risk management assets					
- Short Term	72.2	-	72.2	72.2	112.2
- Long Term	65.1	-	65.1	65.1	138.8
Total risk management assets	137.3	-	137.3	137.3	251.0
Short term debt	-	361.9	361.9	361.9	361.9
Risk management liabilities					
- Short Term	32.4	-	32.4	32.4	126.1
- Long Term	14.0	-	14.0	14.0	298.4
Total risk management liabilities	46.4	-	46.4	46.4	424.5
Debt					
- Current portion of long-term debt recourse	-	205.0	205.0	205.0	205.0
- Current portion of long-term debt non-recourse	-	44.7	44.7	44.7	44.7
- Long-term debt recourse	-	1,681.5	1,681.5	1,681.5	1,686.8
- Long-term debt non-recourse	-	289.6	289.6	289.6	289.6
Total debt	-	2,220.8	2,220.8	2,220.8	2,226.1

[2] *Differences between fair value and carrying value are a result of cash flow hedges that were not previously recorded, but have been accounted for under Section 3865.*

(b) Hedging activities

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

Fair value hedges

We use interest rate swaps to hedge our exposure to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates. We also use foreign exchange contracts to hedge foreign currency denominated assets and liabilities. See Note 5 for a further description of the terms and rates of these swaps.

For the quarter ended March 31, 2007, the ineffective portion of fair value hedges recognized in net income amounted to a pre-tax net unrealized loss of $nil.

Cash flow hedges

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

For the quarter ended March 31, 2007, pre-tax net unrealized loss of $86.7 million were recorded in OCI for the effective portion of the cash flow hedges, and pre-tax unrealized gain of $5.5 million were reclassified to net income. A net unrealized loss of $nil was recognized in income for the ineffective portion.

Net investment hedges

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

For the quarter ended March 31, 2007, the net loss of $2.0 million relating to our net investment in foreign operations was recognized in OCI.

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

Fair value of derivative instruments as at March 31, 2007

(in thousands of dollars)	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated in a hedging relationship	**Total**
Financial Assets					
Derivative instruments	15.2	(0.1)	57.7	47.9	**120.7**
Financial Liabilities					
Derivative instruments	(8.2)	(392.2)	(4.5)	(17.8)	**(422.7)**

4. RISK MANAGEMENT ASSETS AND LIABILITIES

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

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

Balance Sheet	March 31, 2007			Dec. 31, 2006		
	Energy trading	Other	Total	Energy trading	Other	Total
Risk management assets						
- Current	44.5	25.6	70.1	61.0	11.2	72.2
- Long-term	3.2	47.4	50.6	21.9	43.2	65.1
Risk management liabilities						
- Current	(136.1)	(1.8)	(137.9)	(30.3)	(2.1)	(32.4)
- Long-term	(259.0)	(25.8)	(284.8)	(1.0)	(13.0)	(14.0)
Net risk management assets (liabilities) outstanding	(347.4)	45.4	(302.0)	51.6	39.3	90.9

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

Balance Sheet	**March 31, 2007**			Dec. 31, 2006
	Hedges	**Non-Hedges**	**Total**	Total related to energy trading
Risk management assets				
- Current	**$ 0.7**	**$ 43.8**	**$ 44.5**	$ 61.0
- Long-term	**(0.9)**	**4.1**	**3.2**	21.9
Risk management liabilities				
- Current	**(118.5)**	**(17.6)**	**(136.1)**	(30.3)
- Long-term	**(273.3)**	**14.3**	**(259.0)**	(1.0)
Net risk management assets (liabilities) outstanding	**$ (392.0)**	**$ 44.6**	**$ (347.4)**	$ 51.6

The following table illustrates movements in the fair value of the corporation's energy trading net risk management assets separately by source of valuation during the three months ended March 31, 2007:

	Hedges		**Non-Hedges**		
Change in fair value of net assets (liabilities)	**Mark to Market**	**Mark to Model**	**Mark to Market**	**Mark to Model**	**Total**
Net risk management assets outstanding at Dec. 31, 2006 - *as reported*	$ -	$ -	$ 52.7	$ (1.1)	**$ 51.6**
Net risk management assets outstanding at Dec. 31, 2006 - *fair value (Note 1)*	(253.0)	(19.8)	52.7	(1.1)	**(221.2)**
Contracts realized, amortized or settled during the period	5.9	1.4	(13.5)	(0.4)	**(6.6)**
Changes in values attributable to market price and other market changes	(118.0)	(7.2)	3.2	(0.2)	**(122.2)**
New contracts entered into during the current calendar year	(4.8)	-	3.3	4.1	**2.6**
Changes in values attributable to discontinued hedge treatment of certain contracts	3.5	-	(3.5)	-	**-**
Net risk management assets (liabilities) outstanding at March 31, 2007	**$ (366.4)**	**$ (25.6)**	**$ 42.2**	**$ 2.4**	**$ (347.4)**

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

		2007	**2008**	**2009**	**2010**	**2011**	**2012 and thereafter**	**Total**
Hedges	Prices actively quoted	$ (80.9)	$ (129.5)	$ (99.8)	$ (49.7)	$ (4.8)	$ (1.7)	**$ (366.4)**
	Prices based on models	(3.5)	(6.5)	(6.7)	(6.4)	(2.5)	-	**$ (25.6)**
		$ (84.4)	**$ (136.0)**	**$ (106.5)**	**$ (56.1)**	**$ (7.3)**	**$ (1.7)**	**$ (392.0)**
Non-Hedges	Prices actively quoted	$ 42.7	$ (0.8)	$ 0.3	$ -	$ -	$ -	**$ 42.2**
	Prices based on models	1.1	1.1	0.2	-	-	-	**$ 2.4**
		$ 43.8	**$ 0.3**	**$ 0.5**	**$ -**	**$ -**	**$ -**	**$ 44.6**
Grand total		**$ (40.6)**	**$ (135.7)**	**$ (106.0)**	**$ (56.1)**	**$ (7.3)**	**$ (1.7)**	**$ (347.4)**

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

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

	Hedges	Non-Hedges	Total
Net Other Risk Management Assets (Liabilities) at Dec. 31, 2006 - *as reported*	50.1	(10.8)	39.3
Net Other Risk Management Assets (Liabilities) at Dec. 31, 2006 - *fair value*	58.0	(10.3)	47.7
Changes in values attributable to realization of contracts- (gains)/losses	3.4	(0.3)	3.1
Unrealized changes attributable to market price and other market changes -gains/(losses)	(2.7)	(3.8)	(6.5)
Unrealized new contracts entered into during the current calendar year - gains/losses	1.1	-	1.1
Net Other Risk Management Assets (Liabilities) at March 31, 2007 - *fair value*	59.8	(14.4)	45.4

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

Balance Sheet	March 31, 2007			Dec. 31, 2006
	Hedges	Non-Hedges	Total	Total related to non-energy trading
Risk management assets				
- Current	$ 25.6	$ -	$ 25.6	$ 11.2
- Long-term	47.4	-	$ 47.4	43.2
Risk management liabilities				
- Current	(1.8)	-	$ (1.8)	(2.1)
- Long-term	(11.4)	(14.4)	$ (25.8)	(13.0)
Net risk management assets (liabilities) outstanding	$ 59.8	$ (14.4)	$ 45.4	$ 39.3

The corporation's physical electrical transmission contracts trading position was 2.6 million megawatt hours (MWh) at March 31, 2007 compared to 1.5 million MWh at Dec. 31, 2006. The fair value of these contracts are recorded in other assets.

5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Amounts outstanding

	March 31, 2007			Dec. 31, 2006		
	Fair Value [1]	Cost	Interest [2]	Fair Value	Cost	Interest [2]
Debentures, due 2007 to 2033	$ 1,159.4	$ 1,146.1	6.1%	$ 1,161.3	$ 1,146.4	6.1%
Senior Notes, US$600.0 million	687.1	695.2	6.3%	683.6	693.2	6.3%
Non-recourse debt	325.9	325.9	7.7%	334.3	334.3	7.7%
Notes payable - Windsor plant, due 2007 to 2014	45.9	45.9	7.4%	46.9	46.9	7.4%
Preferred securities, due in 2050	-	-	-	175.0	175.0	7.8%
	2,218.3	2,213.1		2,401.1	2,395.8	
Less: current portion	(250.1)	(250.2)		(424.7)	(424.7)	
	$ 1,968.2	$ 1,962.9		$ 1,976.4	$ 1,971.1	

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

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

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

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

3 months ended March 31		2007		2006
Interest on long-term debt	$	38.8	$	34.1
Interest on short-term debt		6.5		3.7
Interest on preferred securities		-		3.4
Interest income		(7.7)		(0.7)
Capitalized interest		(0.3)		-
Net interest expense	$	37.3	$	40.5

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

6. ASSETS HELD FOR SALE

As a result of the decision to stop mining at Centralia, all associated mining and reclamation equipment is being held for sale. All equipment has been recorded at the lower of net book value or anticipated realized proceeds. Due to the strong market for this equipment, it is anticipated that these assets will be sold during 2007. These assets are included in the Generation segment. During the first quarter of 2007 no assets were sold.

7. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

		March 31, 2007		Dec. 31, 2006
Asset retirement obligation	$	332.6	$	328.5
Deferrred revenues and other		19.1		19.7
Power purchase arrangement in limited partnership		26.5		27.1
Accrued benefit liability		60.0		58.0
Centralia mine closure costs		2.6		25.6
	$	440.8	$	458.9
Less: current portion		(46.5)		(48.5)
	$	394.3	$	410.4

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

Balance, Dec. 31, 2006	$	328.5
Liabilities incurred in period		0.9
Liabilities settled in period		(3.2)
Accretion expense		6.0
Change in foreign exchange rates		0.4
Balance, March 31, 2007	**$**	**332.6**

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

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

8. SEGMENTED DISCLOSURES

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

3 months ended March 31, 2007	Generation	CD&M	Corporate	Total
Revenues	**$ 671.9**	**$ 51.8**	**$ -**	**$ 723.7**
Trading purchases	**-**	**(41.3)**	**-**	**(41.3)**
Fuel and purchased power	**(290.7)**	**-**	**-**	**(290.7)**
Gross margin	**381.2**	**10.5**	**-**	**391.7**
Operations, maintenance and administration	**104.0**	**8.6**	**22.5**	**135.1**
Depreciation and amortization	**95.4**	**0.4**	**3.2**	**99.0**
Taxes, other than income taxes	**5.4**	**-**	**0.1**	**5.5**
Intersegment cost allocation	**7.1**	**(7.1)**	**-**	**-**
Operating expenses	**211.9**	**1.9**	**25.8**	**239.6**
Operating income (loss)	**$ 169.3**	**$ 8.6**	**$ (25.8)**	**$ 152.1**
Foreign exchange loss				**0.1**
Net interest expense				**(37.3)**
Equity loss				**(8.9)**
Earnings from operations before income taxes and non-controlling interests				**$ 106.0**

3 months ended March 31, 2006	Generation	CD&M	Corporate	Total
Revenues	$ 680.0	$ 53.7	$ -	$ 733.7
Trading purchases	-	(44.4)	-	(44.4)
Fuel and purchased power	(295.3)	-	-	(295.3)
Gross margin	384.7	9.3	-	394.0
Operations, maintenance and administration	104.4	8.1	20.5	133.0
Depreciation and amortization	98.1	0.3	3.1	101.5
Taxes, other than income taxes	5.5	-	-	5.5
Intersegment cost allocation	6.9	(6.9)	-	-
Operating expenses	214.9	1.5	23.6	240.0
Operating income (loss)	$ 169.8	$ 7.8	$ (23.6)	$ 154.0
Foreign exchange loss				(0.6)
Net interest expense				(40.5)
Equity loss				(1.0)
Earnings from operations before income taxes and non-controlling interests				$ 111.9

II. Selected balance sheet information

March 31, 2007	Generation	Energy Trading	Corporate	Total
Goodwill	**$ 108.2**	**$ 29.5**	**$ -**	**$ 137.7**
Total segment assets	**$ 5,878.6**	**$ 202.4**	**$ 1,171.9**	**$ 7,252.9**

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

III. Selected cash flow information

3 months ended March 31, 2007		**Generation**		**Energy Trading**		**Corporate**		**Total**
Capital expenditures	**$**	**51.1**	**$**	**0.5**	**$**	**2.7**	**$**	**54.3**

3 months ended March 31, 2006								
Capital expenditures	$	25.3	$	1.9	$	2.0	$	29.2
Acqusitions	$	1.2	$	-	$	-	$	1.2

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

3 months ended March 31		**2007**
Depreciation and amortization expense for reportable segments	**$**	**99.0**
Mining equipment depreciation, included in fuel and purchased power		**7.0**
Accretion expense, included in depreciation and amortization expense		**(6.0)**
Other		**(0.1)**
Depreciation and amortization expense per statements of cash flows	**$**	**99.9**

9. 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 March 31, 2007		**Registered**		**Supplemental**		**Other**		**Total**
Current service cost	**$**	**1.1**	**$**	**0.3**	**$**	**0.4**	**$**	**1.8**
Interest cost		**5.1**		**0.6**		**0.3**		**6.0**
Expected return on plan assets		**(6.2)**		**-**		**-**		**(6.2)**
Experience loss		**0.2**		**0.1**		**-**		**0.3**
Past service costs		**-**		**(0.1)**		**0.1**		**-**
Amortization of net transition (asset) obligation		**(2.3)**		**0.1**		**-**		**(2.2)**
Defined benefit (income) expense		**(2.1)**		**1.0**		**0.8**		**(0.3)**
Defined contribution option expense of registered pension plan		**5.8**		**-**		**-**		**5.8**
Net expense	**$**	**3.7**	**$**	**1.0**	**$**	**0.8**	**$**	**5.5**

3 months ended March 31, 2006		Registered		Supplemental		Other		Total
Current service cost	$	1.1	$	0.3	$	0.4	$	1.8
Interest cost		5.0		0.5		0.3		5.8
Expected return on plan assets		(6.4)		-		-		(6.4)
Experience loss		0.7		0.2		0.1		1.0
Amortization of net transition (asset) obligation		(2.3)		0.1		-		(2.2)
Defined benefit (income) expense		(1.9)		1.1		0.8		-
Defined contribution option expense of registered pension plan		5.5		-		-		5.5
Net expense	$	3.6	$	1.1	$	0.8	$	5.5

10. 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 March 31, 2007, the corporation had 202.6 million (Dec. 31, 2006 – 202.4 million) common shares issued and outstanding. During the three months ended March 31, 2007, 0.2 million (2006 – 1.0 million) shares were issued for net proceeds of $4.7 million (2006 – $23.0 million). During the three months ended March 31, 2006 0.7 million shares were issued under the Dividend Reinvestment and Share Purchase Plan for gross proceeds of $17.3 million. Effective Jan. 1, 2007 shares will be purchased on the open market.

B. **Stock options**

At March 31, 2007, the corporation had 1.9 million outstanding employee stock options (Dec. 31, 2006 – 2.2 million). During the first quarter 0.1 million options with a weighted average exercise price of $16.00 were exercised resulting in 0.1 million shares issued. 0.1 million options cancelled or expired with a weighted average exercise price of $16.70. These expired options were mostly part of the U.S. plan.

11. 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.

12. PRIOR PERIOD REGULATORY DECISION

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

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

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

13. GUARANTEES

TransAlta has provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions in various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at March 31, 2007 was a maximum of $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where TransAlta has a net liability at March 31, 2007, under the limited and unlimited guarantees, was $253.0 million as compared to $285.3 million at Dec. 31, 2006.

TransAlta has also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at March 31, 2007 was a maximum of $1.1 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, the corporation has a number of unlimited guarantees. To the extent actual obligations exist under the performance guarantees at March 31, 2007, they are included in accounts payable and accrued liabilities.

A subsidiary of the corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include US$287 million of loans made to subsidiaries of the corporation.

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

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

14. RELATED PARTY TRANSACTIONS

On March 8, 2006, TransAlta Cogeneration LP ("TA Cogen") entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen at market prices during planned maintenance at Sheerness plant in the second quarter of 2006. The swap was settled in the second quarter of 2006 and did not have a material effect on the financial statements.

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

For the period November 2002 to November 2012, TA Cogen entered into various transportation swap transactions with a wholly owned subsidiary of TransAlta, TEC. TEC operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TEC also provides management services to Sheerness, which is operated by Canadian Utilities. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the transaction was the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party, therefore TransAlta has no risk other than counterparty risk.

SUPPLEMENTAL INFORMATION

(Annualized)		March 31 2007	Dec. 31 2006 *(Restated, Note 1)*
Closing market price		**$ 25.00**	$ 26.64
Price range (last 12 months)	High	**$ 27.25**	$ 26.91
	Low	**$ 23.59**	$ 20.22
Debt/invested capital (including non recourse debt)		**41.4%**	40.4%
Debt/invested capital (excluding non recourse debt)		**37.5%**	36.4%
Return on common shareholders' equity		**1.4%**	1.8%
Return on invested capital		**2.4%**	2.5%
Book value per share		**$ 12.40**	$ 12.31
Cash dividends per share		**$ 1.00**	$ 1.00
Price/earnings ratio (times)		**127.4 x**	121.1 x
Dividend payout ratio		**482.8%**	447.7%
Dividend coverage (times)		**3.1 x**	2.4 x
Dividend Yield		**4.0%**	3.8%
Cash Flow to Debt		**26.1%**	26.2%

Ratio Formulas

Debt/invested capital = (short-term debt + long-term debt – cash and interest-earning investments) / (debt + preferred securities + non-controlling interests + common equity)

Return on common shareholders' equity = net earnings excluding gain on discontinued operations / average of opening and closing common equity

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

Book value per share = common shareholders' equity / common shares outstanding

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

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

Dividend payout = dividends / net earnings excluding gain on discontinued operations

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

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

GLOSSARY OF KEY TERMS

Availability - A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, whether or not it is actually generating electricity.

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

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

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

Gigawatt - A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh) - A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

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

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

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

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

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

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