TransAlta™

TRANSALTA CORPORATION
FIRST QUARTER REPORT FOR 2009

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 23 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, 2009 and 2008, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained in our 2008 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated April 28, 2009. Additional information respecting TransAlta, including its annual information form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have two business segments: Generation and Commercial Operations & Development ("COD"). Our segments are supported by a corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items 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	**2009**	2008
Availability (%)	**86.4**	91.8
Production (GWh)	**12,173**	13,226
Revenue	**756**	803
Gross margin[1]	**381**	433
Operating income[1]	**85**	189
Net earnings	**42**	33
Basic and diluted earnings per common share	**0.21**	0.17
Comparable earnings per share[1]	**0.18**	0.50
Cash flow from operating activities	**83**	237
Free cash flow[1]	**(64)**	(31)
Cash dividends declared per share	**0.29**	0.27

1 Gross margin, Operating income, Comparable earnings, and Free cash flow are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 20 of this MD&A for further discussion of these items, including a reconciliation to net earnings and cash flow from operating activities.

	As at March 31, 2009	As at Dec. 31, 2008
Total assets	**7,878**	7,815
Total long-term financial liabilities	**3,210**	3,193

AVAILABILITY & PRODUCTION

Availability for the three months ended March 31, 2009 decreased to 86.4 per cent from 91.8 per cent compared to the same period in 2008 due to higher planned and unplanned outages at the Alberta Thermal plants ("Alberta Thermal"), partially offset by lower planned and unplanned outages at the Centralia Thermal plant ("Centralia Thermal").

Production for the three months ended March 31, 2009 decreased 1,053 gigawatt hours ("GWh") compared to the same period in 2008 due to higher planned and unplanned outages at Alberta Thermal, partially offset by lower planned and unplanned outages at Centralia Thermal.

NET EARNINGS

A reconciliation of net earnings is presented below:

	3 months ended March 31
Net earnings, 2008	33
Decrease in Generation gross margins	(50)
Mark-to-market movements - Generation	(2)
Increase in operations, maintenance, and administration costs	(39)
Increase in depreciation expense	(13)
Decrease in equity loss	97
Decrease in income tax expense	10
Other	6
Net earnings, 2009	**42**

Generation gross margins, net of mark-to-market movements, decreased for the three months ended March 31, 2009 compared to the same period in 2008 as a result of higher planned and unplanned outages at Alberta Thermal and higher coal costs, partially offset by favourable foreign exchange.

Operations, maintenance, and administration ("OM&A") costs for the three months ended March 31, 2009 increased compared to the same period in 2008 primarily due to higher planned outages and unfavourable foreign exchange.

Depreciation expense for the three months ended March 31, 2009 increased compared to the same period in 2008 due to the retirement of certain assets during planned maintenance activities and unfavourable foreign exchange.

In the first quarter of 2008, an equity loss of $97 million was recorded to reflect the writedown of our Mexican investment that was sold in the fourth quarter of the same year.

Income tax expense decreased for the three months ended March 31, 2009 compared to the same period in 2008 due to lower pre-tax earnings in 2009, partially offset by the tax recovery on the writedown of our Mexican investment in 2008.

CASH FLOW

Cash flow from operating activities for the three months ended March 31, 2009 decreased $154 million as a result of lower cash earnings and unfavourable changes in working capital primarily due to the collection of four Alberta Power Purchase Agreement ("PPA") payments in the first quarter of 2008 compared to three in 2009.

Free cash flow for the three months ended March 31, 2009 decreased compared to the same period in 2008 primarily due to lower cash earnings.

SIGNIFICANT EVENTS

Three months ended March 31, 2009

Carbon Capture and Storage

On March 26, 2009, the Government of Canada announced that eight carbon capture and storage ("CCS") projects in Western Canada will share $140 million of funding under its ecoEnergy Technology Initiative, which has been created to develop technologies that are anticipated to reduce carbon dioxide emissions from energy production. The share of this funding for Project Pioneer, our proposed development of Canada's first fully-integrated CCS project, is estimated to be between $20 million and $30 million.

On Jan. 27, 2009, the Government of Canada announced that an additional $850 million of funding has been earmarked to support the development of CCS technologies. The impact of this announcement on TransAlta cannot be reasonably determined at this time because specific information regarding the use, distribution, timelines, and recipients of the funding have not yet been clarified by the government.

Sundance Unit 4 Derate

On Feb. 10, 2009, we reported the first quarter financial impact of an extended derate on Unit 4 of our Sundance thermal plant ("Unit 4"). The facility experienced an unplanned outage in December 2008 related to the failure of an induced draft fan. At that time, Unit 4, which has a capacity of 406 megawatts ("MW"), had been derated to approximately 205 MW. The repair of the induced draft fan components by the original equipment manufacturer took longer than planned, and therefore, Unit 4 did not return to full service until Feb. 23, 2009. As a result of the extended derate, first quarter production and net earnings were reduced by 328 GWh and $17 million, respectively, representing penalties incurred under the Unit 4 PPA and lost merchant revenue.

In response to this event, we have given notice of a High Impact Low Probability Force Majeure Event to the PPA Buyer and the Balancing Pool, which if successful, will protect us from the financial loss of related availability penalties. The availability penalties that we are seeking to recover in net earnings is anticipated to be $14 million, although no assurance can be given as to the timing or amount of any recovery. As required by the appropriate accounting standards, we have recorded a $7 million after-tax provision representing 50 per cent of the total potential recoveries related to this event.

Keephills Units 1 and 2 Uprates

On Jan. 29, 2009, we announced a 46 MW (23 MW per unit) efficiency uprate at Unit 1 and Unit 2 of our Keephills facility. The total capital cost of the project is estimated at $68 million with commercial operations expected to commence by the end of 2011 and 2012, respectively.

Dividend Increase

On Jan. 28, 2009, our Board of Directors declared a quarterly dividend of $0.29 per share on common shares, an increase of $0.02 per share, which on an annual basis will yield $1.16 per share versus $1.08 per share in 2008.

SUBSEQUENT EVENTS

Chief Operating Officer

On April 28, 2009 we announced the appointment of Dawn Farrell to the position of Chief Operating Officer. This change will enhance TransAlta's operational focus and drive greater performance, as well as better integrate the company's growth projects with existing operations. In this new role, Ms. Farrell will lead TransAlta's operations, commercial, engineering, technology and procurement activities. Prior to this appointment, Ms. Farrell was Executive Vice President of Commercial Operations and Development.

Additionally, Richard Langhammer, Executive Vice President of Generation Operations, will take on a new assignment of Chief Productivity Officer for the remainder of 2009 with the responsibility of identifying strategies to create sustainable costs savings across the company. Mr. Langhammer announced his retirement earlier this year; he will formally retire at the end of 2009 after 23 years of service.

Ardenville Wind Power Project

On April 28, 2009, we announced plans to design, build, and operate Ardenville, a 72 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Commercial operations are expected to commence in the first quarter of 2011.

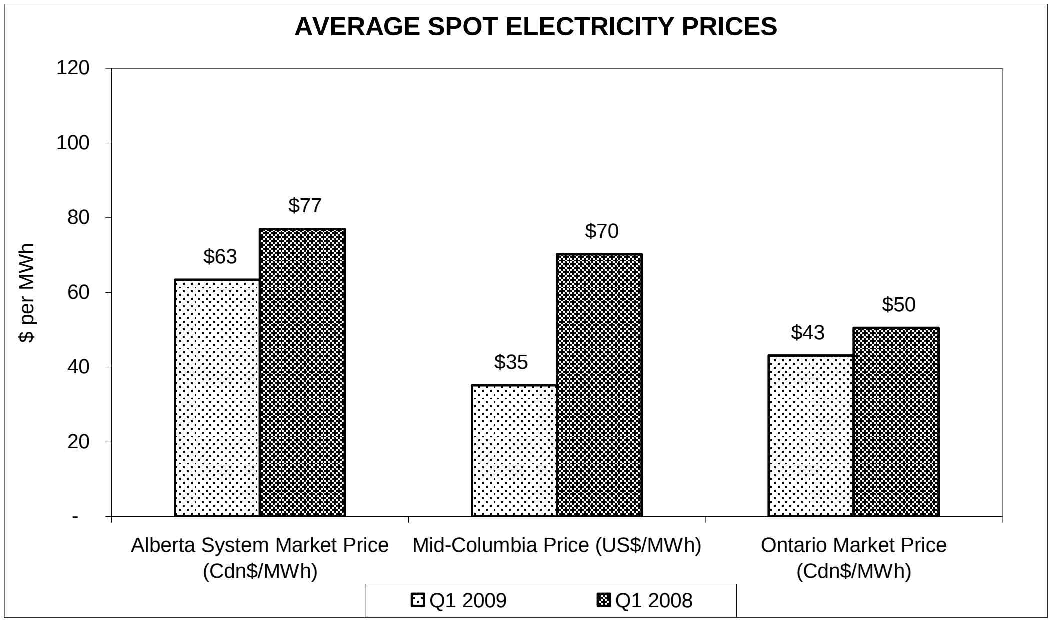
BUSINESS ENVIRONMENT

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Pacific Northwest, and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity and natural gas upon our financial results, *refer to our 2008 Annual Report. The key characteristics of these markets are described below.*

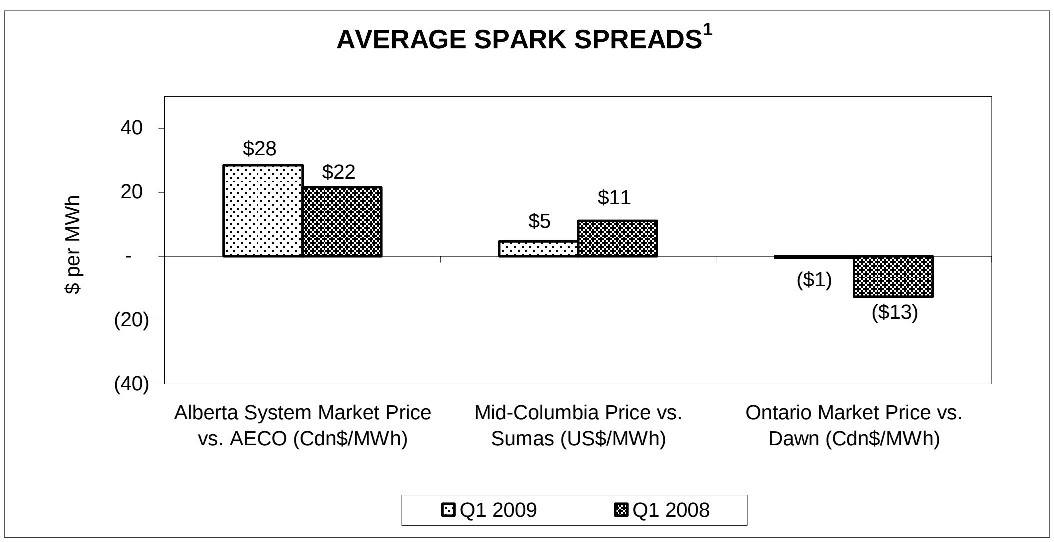
Electricity Prices

Please refer to page 21 of the 2008 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the first quarter of 2009 and 2008 in our three main markets are shown in the following graphs.



For the first quarter of 2009, spot prices decreased in Alberta, the Pacific Northwest, and in Ontario compared to the same period in 2008. While demand remained in line with first quarter levels in 2008, electricity prices in Alberta decreased due to lower natural gas prices. Electricity prices decreased in the Pacific Northwest and Ontario due to lower natural gas prices and decreased demand for electricity. Details on how our contracted assets and hedging activities help reduce the impact of price changes upon our results are discussed in further detail on page 15 of this MD&A.



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

Spark spreads increased in Alberta and Ontario while decreasing in the Pacific Northwest for the three months ended March 31, 2009 compared to the same period in 2008. The increase in Alberta and Ontario spark spreads was a result of power prices decreasing less than natural gas prices. Spark spreads decreased in the Pacific Northwest due to power prices decreasing more than natural gas prices and decreased demand for electricity.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: *Operates hydro, wind, geothermal, natural gas- and coal-fired plants and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support (see the detailed discussion of the four revenue streams in our 2008 Annual Report). At March 31, 2009, Generation had 8,383 MW of gross generating capacity*[1] *in operation (7,976 MW net ownership interest) and 456 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 18 of our 2008 Annual Report.*

The results of the Generation segment are as follows:

3 months ended March 31	**2009 Total**	**2009 Per installed MWh[1]**	2008 Total	2008 Per installed MWh[1]
Revenues	**741**	**40.92**	788	42.78
Fuel and purchased power	**(375)**	**(20.71)**	(370)	(20.09)
Gross margin	**366**	**20.21**	418	22.70
Operations, maintenance and administration	**146**	**8.06**	100	5.43
Depreciation and amortization	**111**	**6.13**	100	5.43
Taxes, other than income taxes	**5**	**0.28**	5	0.27
Intersegment cost allocation	**8**	**0.44**	7	0.38
Operating expenses	**270**	**14.91**	212	11.51
Operating income	**96**	**5.30**	206	11.19
Installed capacity (GWh)	**18,107**		18,418	
Production (GWh)	**12,173**		13,226	
Availability (%)	**86.4**		91.8	

Production and Gross Margins

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

3 months ended March 31, 2009	**Production (GWh)**	**Installed (GWh)**	**Revenue**	**Fuel & purchased power**	**Gross margin**	**Revenue per installed MWh[1]**	**Fuel & purchased power per installed MWh[1]**	**Gross margin per installed MWh[1]**
Western Canada	**7,530**	**11,280**	**273**	**105**	**168**	**24.20**	**9.31**	**14.89**
Eastern Canada	**993**	**1,827**	**118**	**73**	**45**	**64.59**	**39.96**	**24.63**
International	**3,650**	**5,000**	**350**	**197**	**153**	**70.00**	**39.40**	**30.60**
	12,173	**18,107**	**741**	**375**	**366**	**40.92**	**20.71**	**20.21**

3 months ended March 31, 2008	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh[1]	Gross margin per installed MWh[1]
Western Canada	8,758	11,410	360	121	239	31.55	10.57	20.98
Eastern Canada	889	1,789	133	91	42	74.18	51.03	23.14
International	3,579	5,219	295	158	137	56.58	30.35	26.23
	13,226	18,418	788	370	418	42.78	20.11	22.68

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

Western Canada

Our Western Canada assets consist of coal and natural gas-fired plants, hydro facilities, and wind farms. Refer to page 36 of our 2008 Annual Report for further details on our Western operations.

The change in production for the three months ended March 31, 2009 is reconciled below:

	3 months ended March 31 (GWh)
Production, 2008	8,758
Higher planned outages at Alberta Thermal	(586)
Higher unplanned outages at Alberta Thermal	(480)
Timing of planned outages at Sheerness	(121)
Other	(41)
Production, 2009	**7,530**

The change in gross margin for the three months ended March 31, 2009 is reconciled below:

	3 months ended March 31
Gross margin, 2008	239
Higher planned outages at Alberta Thermal	(38)
Higher unplanned outages at Alberta Thermal	(27)
Timing of planned outages at Sheerness	(7)
Mark-to-market movements	4
Higher coal costs	(6)
Other	3
Gross margin, 2009	**168**

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities and one wind farm. Refer to page 37 of our 2008 Annual Report for further details on our Eastern operations.

Production for the three months ended March 31, 2009 increased 104 GWh primarily due to the commissioning of Kent Hills and higher market heat rates at Sarnia.

For the three months ended March 31, 2009, gross margins increased $3 million primarily due to the commissioning of Kent Hills.

International

Our International assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States and natural gas assets in Australia. Refer to page 37 of our 2008 Annual Report for further details on our International operations.

The change in production for the three months ended March 31, 2009 is reconciled below:

	3 months ended March 31 (GWh)
Production, 2008	3,579
Lower planned outages at Centralia Thermal	152
Lower unplanned outages at Centralia Thermal	145
Economic dispatching at Centralia Thermal	(115)
Lower production at natural gas-fired facilities	(109)
Other	(2)
Production, 2009	**3,650**

The change in gross margin for the three months ended March 31, 2009 is reconciled below:

	3 months ended March 31
Gross margin, 2008	137
Higher production at Centralia Thermal	5
Favourable contract pricing	20
Favorable foreign exchange	27
Higher coal costs	(10)
Mark-to-market movements	(6)
Favourable commercial settlements in 2008	(14)
Other	(6)
Gross margin, 2009	**153**

Operations, Maintenance and Administration Expense

OM&A costs for the three months ended March 31, 2009 increased compared to the same period in 2008 primarily due to higher planned outages, unfavourable foreign exchange rates, and the timing of routine maintenance costs.

Depreciation Expense

Depreciation expense for the three months ended March 31, 2009 increased compared to the same period in 2008 due to the retirement of certain assets during planned maintenance activities and unfavourable foreign exchange rates.

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

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

For a more in-depth discussion of our Energy Trading activities, refer to page 38 of our 2008 Annual Report.

The results of the COD segment are as follows:

3 months ended March 31	**2009**	2008
Gross margin	**15**	15
Operations, maintenance and administration	**6**	10
Depreciation and amortization	**1**	-
Intersegment cost allocation	**(8)**	(7)
Operating expenses	**(1)**	3
Operating income	**16**	12

For the three months ended March 31, 2009, COD gross margin is comparable to the same period in 2008.

OM&A costs for the three months ended March 31, 2009 decreased compared to the same period in 2008 due to reduced staff compensation costs.

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

NET INTEREST EXPENSE

3 months ended March 31	**2009**	2008
Interest on long-term debt	**39**	32
Interest on short-term debt	**4**	10
Interest income	**(2)**	(5)
Capitalized interest	**(8)**	(4)
Net interest expense	**33**	33

The change in net interest expense for the three months ended March 31, 2009, compared to the same period in 2008 is shown below:

	3 months ended March 31
Net interest expense, 2008	33
Higher long-term debt levels	3
Lower interest rates on short-term debt	(1)
Lower short-term debt balances	(5)
Lower interest income	3
Higher capitalized interest	(4)
Change in foreign exchange rates	4
Net interest expense, 2009	**33**

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three months ended March 31, 2009 was comparable to the same period in 2008.

INCOME TAXES

3 months ended March 31	**2009**	2008
Earnings before income taxes per statement of earnings	**46**	47
Equity loss	**-**	(97)
Other income	**7**	5
Earnings before income taxes, equity loss and other income	**39**	139
Income tax expense per statement of earnings	**4**	14
Income tax recovery on equity loss	**-**	28
Income tax expense on other income	**-**	(1)
Income tax expense excluding equity loss and other income	**4**	41
Effective tax rate (%)	**10**	29

Income tax expense decreased for the three months ended March 31, 2009 compared to the same period in 2008 due to lower pre-tax earnings in 2009, partially offset by the tax recovery on the writedown of our Mexican investment in 2008.

The effective tax rate decreased for the three months ended March 31, 2009 compared to the same period in 2008 due to lower pre-tax earnings in 2009 and certain deductions that do not fluctuate with earnings.

FINANCIAL POSITION

The following chart highlights significant changes in the Consolidated Balance Sheets from Dec. 31, 2008 to March 31, 2009:

	Increase/ (Decrease)	**Explanation of change**
Accounts receivable	(167)	Timing of customer receipts and lower revenues
Income taxes receivable	23	Tax recovery from current year provision
Risk management assets (current and long-term)	182	Price movements
Property, plant, and equipment, net	70	Capital additions and the weakening of the Canadian dollar relative to the U.S. dollar, partially offset by depreciation expense
Short-term debt	(66)	Repayment of short-term debt
Accounts payable and accrued liabilities	(224)	Timing of operational commitments and the weakening of the Canadian dollar relative to the U.S. dollar
Collateral received	195	Collateral collected from counterparties to reduce the credit risk associated with their obligations
Long-term debt (including current portion)	46	Weakening of the Canadian dollar compared to the U.S. dollar on U.S. denominated debt
Risk management liabilities (current and long-term)	(70)	Price movements
Net future income tax liabilities (including current portions)	73	Tax effect on the increase in net risk management assets
Shareholders' equity	172	Net earnings and movements in AOCI, partially offset by dividends declared

FINANCIAL INSTRUMENTS

Refer to *Note 7* on page 84 of the 2008 Annual Report and the interim consolidated financial statements as at and for the three months ended March 31, 2009 for details on Financial Instruments. During the current quarter, the change in the net asset position of financial instruments resulted from changes in future prices on contracts in our Generation segment. Refer to the 'Risk Management' section in the MD&A of our 2008 Annual Report outlining our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2008.

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under GAAP as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is therefore developed using valuation models or upon internally developed assumptions or inputs. Our Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, or demand profiles. Fair values are validated on a quarterly basis by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At March 31, 2009, Level III financial instruments had a net carrying value of nil (Dec. 31, 2008 – nil).

STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the three months ended March 31, 2009 and 2008:

3 months ended March 31	**2009**	2008	Explanation of change
Cash and cash equivalents, beginning of period	**50**	51	
Provided by (used in):			
Operating activities	**83**	237	Collection of four PPA payments in 2008 compared to three in 2009, and lower cash earnings.
Investing activities	**63**	(113)	Increase in collateral held of $192 million and a decrease in capital spending of $19 million, partially offset by a $25 million decrease in realized gains on financial instruments.
Financing activities	**(148)**	(120)	Increase in repayment of short-term debt of $12 million and a decrease in realized gains on financial instruments of $12 million .
Translation of foreign currency cash	**1**	3	
Cash and cash equivalents, end of period	**49**	58	

LIQUIDITY AND CAPITAL RESOURCES

Details on our liquidity needs and capital resources can be found on page 46 of our 2008 Annual Report.

Our ability to generate adequate cash flow from operations, maintain our financial capacity and flexibility, and to provide for planned growth remains substantially unchanged since Dec. 31, 2008.

Debt

Short-term, recourse and non-recourse debt totalled $2,788 million at March 31, 2009 compared to $2,808 million at Dec. 31, 2008. Short-term debt decreased as a result of an increase in collateral received, which was used to repay short-term debt balances. Long-term debt increased due to the weakening of the Canadian dollar compared to the U.S. dollar on our U.S. dollar-denominated debt.

Credit

We have a total of $2.2 billion of committed credit facilities of which $1.5 billion is not drawn and is available as of March 31, 2009, subject to customary borrowing conditions. At March 31, 2009, credit utilized under these facilities is $0.7 billion, which is comprised of short-term debt of $377 million, not including cash on hand of $49 million, and of letters of credit of $374 million.

Our primary source for short-term liquidity is our $1.5 billion committed syndicated bank facility, which matures in 2012. We anticipate renewing this facility, based on reasonable commercial terms, prior to its maturity.

Share Capital

On April 27, 2009, we had approximately 198 million common shares outstanding.

At March 31, 2009, we had 1.7 million outstanding employee stock options with a weighted average exercise price of $27.18. For the three months ended March 31, 2009, options with a weighted average exercise price of $17.33 were exercised at a total cost of $0.1 million.

Normal Course Issuer Bid (“NCIB”) Program

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

For the three months ended March 31, 2009, we purchased no shares under the NCIB program.

For the three months ended March 31, 2008, we purchased 1,908,900 shares under the NCIB program at an average price of $31.43 per share. The shares were purchased for an amount higher than their weighted average book value of $8.95 per share resulting in a reduction of retained earnings of $43 million.

3 months ended March 31	**2009**	2008
Total shares purchased	**-**	1,908,900
Average purchase price per share	**-**	31.43
Total cost	**-**	60
Weighted average book value of shares cancelled	**-**	17
Reduction to retained earnings	**-**	43

Credit Risk

Credit risk is the risk to our business associated with changes in creditworthiness of entities with which we have commercial exposures. Refer to page 55 of our 2008 Annual Report for further details on our credit risk management profile and practices.

While we had no counterparty losses in the first quarter of 2009, we continue to keep a close watch on changes and trends in the market and the impact these changes could have on our trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

We are exposed to minimal credit risk from our Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. Our credit risk management profile and practices have not changed materially since Dec. 31, 2008.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At March 31, 2009, we provided letters of credit totaling $374 million (Dec. 31, 2008 – $430 million) and cash collateral of $28 million (Dec. 31, 2008 – $37 million). The decrease in letters of credit and cash collateral is due primarily to lower forward electricity prices in the Pacific Northwest. These letters of credit and cash collateral secure certain amounts included on our balance sheet under “Risk Management Liabilities” and “Asset Retirement Obligations”.

CLIMATE CHANGE AND THE ENVIRONMENT

In the first quarter of 2009, there were no significant changes to existing environmental legislation in Canada. The Canadian Federal Government continues to develop its greenhouse gas (“GHG”) regulations under the Canadian Environmental Protection Act and they are anticipated to come into effect in 2010.

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

On March 31, 2009, in response to the Alberta Government’s $2 billion initiative to support the early deployment of CCS, we submitted a full project proposal to Alberta for joint industry–government funding for the development of Project Pioneer, our proposed CCS facility. The government’s decision on the amount of support to be provided to successful projects is expected by June 30, 2009.

Additional CCS funding was announced on March 26, 2009, when the Canadian Federal Government announced that our Project Pioneer had been awarded federal financial support under its ecoEnergy Technology Initiative. Our share of this funding is estimated to be between $20 million and $30 million. Also, on Jan. 27, 2009, the Government of Canada announced in the 2009 federal budget an additional $850 million of funding earmarked to support the development of CCS technologies. The impact of this announcement on TransAlta cannot be reasonably determined at this time because specific information regarding the use, distribution, timelines, and recipients of the funding have not yet been clarified by the government

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

In the United States, Washington State is developing legislation to address climate change initiatives within the State. Various draft bills have been debated but to date no final direction has been determined and no legislation has been passed. At this point, there are no indications as to how these initiatives will impact our fossil-fired assets in the state of Washington.

On March 31, 2009, we reached an agreement with the Washington Department of Ecology to voluntarily reduce the emissions of mercury and nitrogen oxide ("NOx") from Centralia Thermal. Our voluntary actions will start in 2009 and are estimated to result in a 20 per cent reduction in NOx emissions by 2018 and a 50 per cent reduction in mercury emissions by 2012. A 30-day public comment period on the proposed agreement is expected to be announced by the state of Washington in the next quarter.

U.S. federal legislation on GHGs continues to be discussed. On March 31, 2009, the draft American Clean Energy and Security Act of 2009 was released which, if enacted, would implement a greenhouse cap and trade system by 2012. The proposed system would cover 85 per cent of the GHG emissions in the U.S., including those from electricity generation. The draft Act proposes reduction caps of three per cent below 2005 levels in 2012, moving to 20 per cent below by 2020. As important details on allowance allocation have yet to be decided, it is not yet possible to determine the impact the draft bill would have on our U.S. operations, should the legislation be passed.

OUTLOOK

For 2009, we anticipate low single-digit growth in comparable earnings per share based upon the significant factors that are discussed below.

Business Environment

Economic Environment

As a result of the current economic environment, commodity prices are decreasing, which could result in lower input costs for us in the future. Although we have contracted the price of the majority of our inputs in the short-term, in the longer-term we may see the benefit of lower operating costs.

A number of financial and industrial counterparties have experienced credit rating downgrades and we expect 2009 will continue to be a challenging year for some of our counterparties. While we had no counterparty losses in the first quarter of 2009, we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

We expect continued strict lending conditions, which could reduce the amount of capital available. Our strong financial position, available committed lines of credit, and relatively low debt maturity profile allow us to be selective about when we need to go to the market for financing. We see support in the market for successful projects with high returns, so we will continue to evaluate potential projects using the risk management policies that have been developed and take action when appropriate.

While we do expect our results from operations in 2009 to be somewhat impacted by the current economic environment, this impact is largely mitigated by the contracted production and prices through our PPAs and other long-term contracts.

Power Prices

For the remainder of 2009, power prices are expected to remain lower than 2008 due to the persistence of low natural gas prices and weaker demand for electricity in the Pacific Northwest and Ontario.

Environmental Legislation

For the remainder of 2009, we anticipate increasing regulatory clarity on future GHG requirements from both the Canadian and U.S. governments. Given recent government announcements, we are anticipating environmental regulations to be developed in line with a cap and trade system.

In Alberta, current regulations on GHGs and air pollutants are clear, but it is uncertain how future federal regulations may affect Alberta firms. We expect discussions to take place in 2009 between the Federal Government and the provinces about what rules are to be applied and their administration. In Washington State, we expect to see details of the State's climate change legislation by the end of 2009.

We are active participants in consultations leading up to the formation of these legislative and regulatory mechanisms.

Operations

Production, Availability, and Capacity

Generating capacity is expected to increase due to the completion of Blue Trail and the uprate at Sundance Unit 5 in late 2009. Production and availability are expected to decrease in the second quarter compared to the first quarter due to increased planned maintenance and from economic dispatch opportunities at Centralia Thermal. Production and availability are then expected to increase in the second half of 2009 due to lower planned and unplanned outages. Overall fleet availability for 2009 is expected to be between 88 and 89 per cent.

Commodity Hedging

Through the Alberta PPAs and our other long-term contracts, approximately 70 per cent of our capacity is contracted for a period of more than 10 years. To provide further stability to future earnings, we enter into physical and financial contracts for periods of up to four years. Under this strategy, we target being at least 90 per cent contracted for the upcoming year, stepping down to 75 per cent in the fourth year. As at the end of the first quarter, approximately 95 per cent of our 2009 capacity and 85 per cent of our 2010 capacity is contracted with the average contracted price in 2009 of $60-65/MWh in Alberta and U.S.$50-55/MWh in the Pacific Northwest.

We continue to closely monitor the risks associated with commodity price changes on our future operations and, where we consider appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Fuel Costs

Coal costs in Alberta are subject to increases related to mining such as increased overburden removal, inflation, and increases in commodity prices. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Although the risk of cost increases due to commodity prices is much lower, coal costs for the remainder of 2009, on a standard cost basis, are expected to increase five per cent from the prior year primarily due to increased capital expenditures in 2008.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for the remainder of 2009 is expected to increase between 10 and 15 per cent from the prior year due to rail and transportation contract escalations.

Our natural gas-fired facilities have minimal exposure to market fluctuations in energy commodity prices. Exposure to natural gas costs for facilities under long-term sales contracts are minimized to the extent possible through long-term natural gas purchase contracts. Merchant natural gas facilities are exposed to the changes in spark spreads because the majority of the natural gas is purchased on a spot basis. The input costs that are purchased on a spot basis benefited from lower prices seen throughout the first quarter, which is in line with our expectations for the remainder of the year.

Operations, Maintenance, and Administration Costs

OM&A costs per megawatt hour (“MWh”) of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per installed MWh for the remainder of 2009 are expected to increase slightly in the second quarter and then decrease in the second half of the year primarily as a result of minimal planned maintenance activities. Excluding major maintenance costs, OM&A costs are expected to remain in line with 2008 levels through cost savings and productivity initiatives.

Energy Trading

Earnings from our COD segment are affected by prices in the market, the positions taken, and duration of those positions. We continuously monitor both the market and our exposure with the view to maximize earnings while still maintaining an acceptable risk profile. Our 2009 objective remains for Energy Trading to contribute between $65 million and $85 million in 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 and Australian dollar by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign-denominated currency expenses, including interest charges, which serve as a natural hedge for a portion of our foreign currency revenues.

Net Interest Expense

Net interest expense for the remainder of 2009 is expected to be higher compared to the prior year mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar will affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, there may be the need for additional liquidity. To mitigate this liquidity risk, we maintain and monitor $2.2 billion of committed credit facilities as well as monitor exposures to determine expected liquidity requirements.

Accounting Estimates

Although we do not expect significant changes in our accounting estimates as a result of the current economic environment, some fluctuation could be seen on the fair valuation of our risk management assets and liabilities due to large variation in future commodity prices and foreign exchange and interest rate forward curves. Any significant changes in forward prices and rates could result in material differences in the amount of unrealized gains or losses and risk management assets and liabilities recorded at each reporting date due to the fair valuation performed at that time. However, any such change in fair value will not impact cash flow as we will continue to receive our contracted prices associated with Generation asset contracts.

Capital Expenditures

Projects and Growth

Our major projects are comprised of spending to sustain our current operations and for growth activities. Seven significant growth capital projects are currently in progress as outlined in the table below:

	Total Project		2009		Target	
Project	**Estimated spend**	**Spent to date**	**Estimated spend**	**Spent to date**	**completion date**	**Details**
Keephills 3	888	523	235 - 255	47	Q1 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with EPCOR
Blue Trail	115	30	85 - 90	4	Q4 2009	A 66 MW wind farm in southern Alberta
Sundance Unit 5 uprate	75	22	50 - 60	5	Q4 2009	A 53 MW efficiency uprate at our Sundance facility
Summerview 2	123	26	80 - 90	1	Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	-	5 - 10	-	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	-	5 - 10	-	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	-	25 - 35	-	Q1 2011	A 72 MW wind farm in southern Alberta
Total growth	**1,404**	**601**	**485- 550**	**57**		

Sustaining Expenditures

For 2009, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected spend	Spent to date
Routine capital	Expenditures to maintain our existing generating capacity	115 - 135	40
Productivity capital	Projects to improve power production efficiency	40 - 45	12
Mining equipment and land purchases	Expenditures related to mining equipment and land	35 - 45	5
Centralia modifications	Capital project to convert to external coal	20 - 25	1
Planned maintenance	Regularly scheduled major maintenance	130 - 140	18
Total sustaining expenditures		**340 - 390**	**76**

Details of the 2009 planned maintenance program are outlined as follows:

	Coal	Gas and hydro	Expected spend	Spent to date
Capitalized	90 - 95	40 - 45	**130 - 140**	**18**
Expensed	90 - 95	0 - 5	**90 - 100**	**36**
	180 - 190	40 - 50	**220 - 240**	**54**
GWh lost	2,800 - 2,900	200 - 225	**3,000 - 3,125**	**751**

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities and from existing borrowing capacity. The funds required for committed growth and sustaining projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flows and amount of committed credit available at March 31, 2009.

RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership (“TAGP”), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership with Keephills 3 Limited Partnership (“K3LP”), a wholly owned subsidiary of the Corporation, and EPCOR Power Development Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at March 31, 2009, TAGP had received $44 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

CE Generation, LLC has entered into contracts with related parties to provide administrative and maintenance services. The values of these contracts are U.S.$3 million for the years ending Dec. 31, 2009 and 2010.

For the period November 2002 to November 2012, one of our subsidiaries, TransAlta Cogeneration, L.P. ("TA Cogen"), entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. We entered into an offsetting contract and therefore have no risk other than counterparty risk.

CURRENT ACCOUNTING CHANGES

Credit Risk

On Jan. 1, 2009, we adopted the Emerging Issues Committee ("EIC") Abstract EIC-173 *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC–173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. The implementation of this standard did not have a material impact upon our Consolidated Balance Sheets, Consolidated Statements of Earnings or Consolidated Statements of Cash Flows.

Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, we adopted Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 incorporates material from International Accounting Standard 38, *Intangible Assets*, addressing when an internally developed intangible asset meets the criteria for recognition as an asset, which requires a demonstration of technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset. The implementation of this standard did not have a material impact upon our Consolidated Balance Sheets, Consolidated Statements of Earnings or Consolidated Statements of Cash Flows.

Mining Exploration Costs

On Jan. 1, 2009, we adopted EIC–174, *Mining Exploration Costs*. EIC–174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have a material impact upon our Consolidated Balance Sheets, Consolidated Statements of Earnings or Consolidated Statements of Cash Flows.

FUTURE ACCOUNTING CHANGES

Financial Instrument Disclosures

On March 5, 2009, the International Accounting Standards Board ("IASB") issued *Improving Disclosures about Financial Instruments (Amendments to International Financial Reporting Standard ("IFRS") 7)*. The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. The Accounting Standards Board of Canada ("AcSB") has indicated that it intends to adopt similar requirements by mid-2009, at which time these requirements will be effective for us. It is not anticipated that the impacts of adopting this standard will be significant, as many of the expanded disclosure requirements are already provided as part of our existing financial instrument disclosures.

IFRS Convergence

At the IFRS Advisory Committee Meeting held on Jan. 14, 2009, the AcSB re-confirmed that the use of IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that must be addressed. In addition, there is significantly more disclosure required, specifically for interim reporting.

Our project to convert to IFRS commenced in late 2007 and consists of four phases: diagnostic, design and planning, solution development, and implementation. The diagnostic phase has been completed for the IFRS standards expected to be effective on convergence. The IFRS project has entered the design and planning stage with issue-specific teams being established to further analyze the key areas of convergence and coordinate with Information Technology and Internal Control resources to determine process and system changes along with appropriate financial reporting controls. Staff training programs are also in the design and planning stages and a communication plan is in place.

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

Based on work to-date, our initial view is that there are many similarities between Canadian GAAP and IFRS and that the major differences for us will likely arise in respect of property, plant, and equipment, the impairment of long-lived assets, and accounting for long-term contracts. We continue to carefully evaluate the transitional options available under IFRS at the adoption date, the most appropriate long-term accounting policies. Accordingly, the full impact of adopting IFRS on our future financial position and future results cannot be reasonably determined at this time.

The IASB is currently undertaking several IFRS projects which will likely result in significant changes to existing IFRS standards in areas such as financial statement presentation, leases, revenue recognition, and post-employment benefits. At this time, it is not anticipated that any resulting new standards will be effective on convergence in 2011. However, the progress and recommendations of these IASB projects are being monitored closely to ensure that any potential adverse impacts to the convergence project can be minimized.

NON-GAAP MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below are not defined under GAAP and therefore should not be considered in isolation or as an alternative to or more meaningful than net income or cash flow from operating activities, as determined in accordance with GAAP, as an indicator of our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

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

Net Earnings Reconciliation

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

3 months ended March 31	2009	2008
Revenues	**756**	803
Fuel and purchased power	**(375)**	(370)
Gross margin	**381**	433
Operations, maintenance, and administration	**174**	135
Depreciation and amortization	**117**	104
Taxes, other than income taxes	**5**	5
Operating expenses	**296**	244
Operating income	**85**	189
Foreign exchange gain (loss)	**1**	(1)
Net interest expense	**(33)**	(33)
Equity loss	**-**	(97)
Other income	**7**	5
Earnings before non-controlling interests and income taxes	**60**	63
Non-controlling interests	**14**	16
Earnings before income taxes	**46**	47
Income tax expense	**4**	14
Net earnings	**42**	33

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Earnings on a comparable basis are based on earnings per share and are additive quarter over quarter.

In calculating comparable earnings for 2009, we have excluded the settlement of an outstanding commercial issue that has been recorded in other income as this was related to our previously held Mexican investment.

The change in life of certain component parts at Centralia Thermal was excluded from the calculation of comparable earnings in 2009 and 2008 as it is relates to the cessation of mining activities at the Centralia coal mine and conversion to consuming solely third party supplied coal.

In calculating comparable earnings for 2008, we have also excluded the writedown of our Mexican investment. We also excluded the gains recorded on the sale of assets at the previously operated Centralia coal mine as we do not normally dispose of large quantities of fixed assets.

3 months ended March 31	2009	2008
Net earnings	**42**	33
Sale of assets at Centralia, net of tax	**-**	(4)
Change in life of Centralia parts, net of tax	**1**	5
Other income	**(7)**	-
Writedown of Mexican investment, net of tax	**-**	65
Earnings on a comparable basis	**36**	99
Weighted average common shares outstanding in the period	**198**	200
Earnings on a comparable basis per share	**0.18**	0.50

Free Cash Flow

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

Sustaining capital expenditures for the three months ended March 31, 2009, represents total capital expenditures per the Consolidated Statements of Cash Flow less $62 million ($57 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2008, we invested $73 million ($67 million net of joint venture contributions) in growth projects.

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

3 months ended March 31	**2009**	2008
Cash flow from operating activities	**83**	237
Add (Deduct):		
Sustaining capital expenditures	**(69)**	(83)
Dividends on common shares	**(54)**	(51)
Distribution to subsidiaries' non-controlling interest	**(16)**	(17)
Non-recourse debt repayments	**(1)**	-
Timing of contractually scheduled payments	**-**	(116)
Other income	**(7)**	-
Cash flows from equity investments	**-**	(1)
Free cash flow	**(64)**	(31)

Cash flows from equity investments represent operational cash flow from our previously owned equity accounted investments less capital expenditures for such investments.

SELECTED QUARTERLY INFORMATION

	Q2 2008	Q3 2008	Q4 2008	**Q1 2009**
Revenue	708	791	808	**756**
Net earnings	47	61	94	**42**
Basic earnings per common share	0.24	0.31	0.47	**0.21**
Diluted earnings per common share	0.24	0.31	0.47	**0.21**

	Q2 2007	Q3 2007	Q4 2007	Q1 2008
Revenue	612	711	783	803
Net earnings	57	66	130	33
Basic earnings per common share	0.28	0.33	0.64	0.17
Diluted earnings per common share	0.28	0.33	0.64	0.17

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934 (“Exchange Act”), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, the Corporation’s internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2009, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD-LOOKING STATEMENTS

This document, documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as *"may"*, *"will"*, *"believe"*, *"expect"*, *"anticipate"*, *"intend"*, *"plan"*, *"foresee"*, *"potential"*, *"enable"*, *"continue"* or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause TransAlta's actual performance to be materially different from those projected.

Factors that may adversely impact our forward-looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate our facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) our provision for income taxes; (xvi) legal proceedings involving us; (xvii) reliance on key personnel; (xviii) labour relations matters; and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" on page 22 of our 2008 Annual Information Form and on page 53 of our 2008 Annual Report.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward-looking events might or might not occur. We cannot assure you that projected results or events will be achieved.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2009**	2008
Revenues	**756**	803
Fuel and purchased power	**(375)**	(370)
	381	433
Operations, maintenance, and administration	**174**	135
Depreciation and amortization *(Note 21)*	**117**	104
Taxes, other than income taxes	**5**	5
	296	244
	85	189
Foreign exchange gain (loss)	**1**	(1)
Net interest expense *(Note 8)*	**(33)**	(33)
Equity loss	**-**	(97)
Other income *(Note 11)*	**7**	5
Earnings before non-controlling interests and income taxes	**60**	63
Non-controlling interests	**14**	16
Earnings before income taxes	**46**	47
Income tax expense *(Note 7)*	**4**	14
Net earnings	**42**	33
Retained earnings		
Opening balance	**688**	763
Common share dividends	**(57)**	(54)
Common shares cancelled under NCIB *(Note 14)*	**-**	(43)
Closing balance	**673**	699
Weighted average number of common shares outstanding in the period	**198**	200
Net earnings per share, basic and diluted	**0.21**	0.17

See accompanying notes

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

Unaudited	**March 31, 2009**	Dec. 31, 2008
Cash and cash equivalents *(Note 3)*	**49**	50
Accounts receivable *(Notes 3 and 19)*	**338**	505
Collateral paid *(Notes 2 and 3)*	**28**	37
Prepaid expenses	**15**	6
Risk management assets *(Notes 3, 4, and 5)*	**296**	200
Future income tax assets	**6**	3
Income taxes receivable	**84**	61
Inventory *(Note 6)*	**57**	51
	873	913
Restricted cash *(Note 3)*	**2**	-
Long-term receivables *(Note 9)*	**8**	14
Property, plant, and equipment		
Cost	**10,128**	9,932
Accumulated depreciation	**(4,024)**	(3,898)
	6,104	6,034
Goodwill *(Note 21)*	**145**	142
Intangible assets	**207**	213
Future income tax assets	**179**	248
Risk management assets *(Notes 3, 4, and 5)*	**307**	221
Other assets	**53**	30
Total assets	**7,878**	7,815
Short-term debt *(Note 3)*	**377**	443
Accounts payable and accrued liabilities *(Note 3)*	**434**	658
Collateral received *(Notes 2 and 3)*	**219**	24
Risk management liabilities *(Notes 3, 4, and 5)*	**114**	148
Income taxes payable	**12**	15
Future income tax liabilities	**15**	14
Dividends payable	**55**	52
Current portion of long-term debt - recourse *(Notes 3 and 8)*	**212**	211
Current portion of long-term debt - non-recourse *(Notes 3 and 8)*	**33**	33
Current portion of asset retirement obligations *(Note 9)*	**48**	45
	1,519	1,643
Long-term debt - recourse *(Notes 3 and 8)*	**1,927**	1,889
Long-term debt - non-recourse *(Notes 3 and 8)*	**239**	232
Asset retirement obligations *(Note 9)*	**250**	252
Deferred credits and other long-term liabilities *(Note 10)*	**126**	122
Future income tax liabilities	**602**	596
Risk management liabilities *(Notes 3, 4, and 5)*	**66**	102
Non-controlling interests *(Note 12)*	**467**	469
Common shareholders' equity		
Common shares *(Notes 13 and 14)*	**1,767**	1,761
Retained earnings *(Note 14)*	**673**	688
Accumulated other comprehensive income *(Note 14)*	**242**	61
Total shareholders' equity	**2,682**	2,510
Total liabilities and shareholders' equity	**7,878**	7,815

Contingencies *(Notes 17 and 19)*
Commitments *(Notes 4 and 18)*
Subsequent events *(Note 23)*

See accompanying notes

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

	3 months ended March 31	
Unaudited	**2009**	2008
Net earnings	**42**	33
Other comprehensive income (loss)		
Gains on translating net assets of self-sustaining foreign operations	**62**	67
Losses on financial instruments designated as hedges of self-sustaining foreign operations	**(50)**	(83)
Tax recovery	**7**	11
Net losses on financial instruments designated as hedges of self-sustaining operations	**(43)**	(72)
Gains (losses) on translation of self-sustaining foreign operations	**19**	(5)
Gains (losses) on derivatives designated as cash flow hedges	**280**	(229)
Tax (expense) recovery	**(91)**	80
Gains (losses) on derivatives designated as cash flow hedges	**189**	(149)
Derivatives designated as cash flow hedges in prior periods transferred to balance sheet in the current period	**(4)**	4
Derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period	**(38)**	17
Tax recovery (expense)	**15**	(7)
Reclassification of derivatives designated as cash flow hedges	**(27)**	14
Other comprehensive income (loss)	**181**	(140)
Comprehensive income (loss)	**223**	(107)

See accompanying notes

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2009**	2008
Operating activities		
Net earnings	**42**	33
Depreciation and amortization *(Note 21)*	**121**	107
Gain on sale of equipment	**-**	(5)
Non-controlling interests	**14**	16
Asset retirement obligation accretion *(Note 9)*	**6**	5
Asset retirement costs settled *(Note 9)*	**(8)**	(4)
Future income taxes	**19**	(16)
Unrealized losses from risk management activities	**-**	1
Unrealized foreign exchange (gain) loss	**(3)**	1
Equity loss	**-**	97
Other non-cash items	**-**	(2)
	191	233
Change in non-cash operating working capital balances	**(108)**	4
Cash flow from operating activities	**83**	237
Investing activities		
Additions to property, plant, and equipment	**(131)**	(150)
Proceeds on sale of property, plant, and equipment	**1**	16
Restricted cash	**(1)**	3
Realized (losses) gains on financial instruments	**(6)**	19
Collateral received from counterparties	**192**	-
Collateral paid to counterparties	**9**	-
Settlement of adjustments on sale of Mexican investment *(Note 10)*	**(7)**	-
Other	**6**	(1)
Cash flow from (used in) investing activities	**63**	(113)
Financing activities		
Decrease in short-term debt	**(76)**	(64)
Repayment of long-term debt	**(2)**	(4)
Dividends paid on common shares	**(54)**	(51)
Funds paid to repurchase common shares under NCIB *(Note 14)*	**-**	(7)
Realized gains on financial instruments	**-**	12
Distributions paid to subsidiaries' non-controlling interests	**(16)**	(17)
Other	**-**	11
Cash flow used in financing activities	**(148)**	(120)
Cash flow (used in) from operating, investing, and financing activities	**(2)**	4
Effect of translation on foreign currency cash	**1**	3
(Decrease) increase in cash and cash equivalents	**(1)**	7
Cash and cash equivalents, beginning of period	**50**	51
Cash and cash equivalents, end of period	**49**	58
Cash taxes paid	**23**	46
Cash interest paid	**15**	19

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

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

1. ACCOUNTING POLICIES

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

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

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

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

2. ACCOUNTING CHANGES

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

During 2009 specifically, collateral posted was presented separately on the Consolidated Balance Sheets from accounts receivable. In 2008, $37 million was also reclassified in order to present comparable figures.

During 2009, collateral received by the Corporation was presented separately on the Consolidated Balance Sheets from accounts payable. In 2008, $24 million was also reclassified in order to present comparable figures.

Current Accounting Changes

Credit Risk

On Jan. 1, 2009, the Corporation adopted the Emerging Issues Committee ("EIC") Abstract 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC-173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Disclosure required as a result of adopting this standard can be found in Note 4.

Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, the Corporation adopted Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*. Section 3064 incorporates material from International Accounting Standard 38, *Intangible Assets*, addressing when an internally developed intangible asset meets the criteria for recognition as an asset, which requires a demonstration of technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset. The implementation of this standard did not have a material impact upon the Consolidated Balance Sheets, Consolidated Statements of Earnings or Consolidated Statements of Cash Flows.

Mining Exploration Costs

On Jan. 1, 2009, the Corporation adopted EIC–174, *Mining Exploration Costs.* EIC-174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have a material impact upon the Consolidated Balance Sheets, Consolidated Statements of Earnings or Consolidated Statements of Cash Flows.

Future Accounting Changes

Financial Instrument Disclosures

On March 5, 2009, the International Accounting Standards Board ("IASB") issued *Improving Disclosures about Financial Instruments (Amendments to International Financial Reporting Standard ("IFRS") 7)*. The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. The Accounting Standards Board of Canada ("AcSB") has indicated that it intends to adopt similar requirements by mid-2009, at which time these requirements will be effective for TransAlta. It is not anticipated that the impacts of adopting this standard will be significant, as many of the expanded disclosure requirements are already provided as part of the Corporation's existing financial instrument disclosures.

IFRS Convergence

At the IFRS Advisory Committee Meeting held on Jan. 14, 2009, the AcSB re-confirmed that the use of IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that must be addressed. In addition, there is significantly more disclosure required, specifically for interim reporting.

TransAlta's project to convert to IFRS commenced in 2007. The IFRS project has entered the design and planning stage with issue-specific teams being established to further analyze and develop plans for the key areas of convergence.

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

TransAlta continues to carefully evaluate the transitional options available under IFRS at the adoption date, the most appropriate long-term accounting policies. Accordingly, the full impact of adopting IFRS on TransAlta's future financial position and future results cannot be reasonably determined at this time.

3. FINANCIAL INSTRUMENTS

A. Analysis of Financial Assets and Liabilities by Measurement Basis

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost. The disclosures in the "Financial Instruments and Hedges" section of Note 1(N) to the Corporation's 2008 annual consolidated financial statements describe how the categories of financial instruments are measured and how income and expenses, including fair value gains and losses, are recognized. The following table classifies the carrying amounts of the financial assets and liabilities by category:

Carrying value of financial instruments as at March 31, 2009

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	-	-	49	-	49
Accounts receivable	-	-	338	-	338
Collateral paid	-	-	28	-	28
Risk management assets					
Current	202	94	-	-	296
Long-term	307	-	-	-	307
Restricted cash	-	-	2	-	2
Financial liabilities			.		
Short-term debt	-	-	-	377	377
Accounts payable and accrued liabilities	-	-	-	434	434
Collateral received	-	-	-	219	219
Risk management liabilities					
Current	28	86	-	-	114
Long-term	60	6	-	-	66
Long-term debt recourse[1]	-	-	-	2,139	2,139
Long-term debt non-recourse[1]	-	-	-	272	272

Carrying value of financial instruments as at Dec. 31, 2008

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total carrying value
Financial assets					
Cash and cash equivalents	-	-	50	-	50
Accounts receivable	-	-	505	-	505
Collateral paid	-	-	37	-	37
Risk management assets					
Current	121	79	-	-	200
Long-term	220	1	-	-	221
Financial liabilities					
Short-term debt	-	-	-	443	443
Accounts payable and accrued liabilities	-	-	-	658	658
Collateral received	-	-	-	24	24
Risk management liabilities					
Current	74	74	-	-	148
Long-term	96	6	-	-	102
Long-term debt recourse[1]	-	-	-	2,100	2,100
Long-term debt non-recourse[1]	-	-	-	265	265

[1] *Includes current portion.*

B. Fair Value of Financial Instruments

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

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

I. Level Determinations and Classifications

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

	Fair value [1]				Total carrying
As at March 31, 2009	**Level I**	**Level II**	**Level III**	**Total**	**value**
Financial assets and liabilities measured at fair value					
Net risk management assets [2]	1	422	-	423	423
Financial assets and liabilities measured at other than fair value					
Long-term debt	-	2,234	-	2,234	2,411

	Fair value [1]				Total carrying
As at Dec. 31, 2008	**Level I**	**Level II**	**Level III**	**Total**	**value**
Financial assets and liabilities measured at fair value					
Net risk management assets [2]	1	170	-	171	171
Financial assets and liabilities measured at other than fair value					
Long-term debt	-	2,099	-	2,099	2,365

[1] *Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, short-term debt, and accounts payable and accrued liabilities).*
[2] *Includes Energy Trading and Other Risk Management Assets and Liabilities on a net basis (Note 4).*

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

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

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined is estimated to be an increase/decrease in net fair values as at March 31, 2009 of $1 million (March 31, 2008 - nil). This estimate is based on a +/- one standard deviation move from the mean.

The total change in fair value estimated using a valuation technique with unobservable inputs, for financial assets and liabilities measured and recorded at fair value, that was recognized in pre-tax earnings for the three months ended March 31, 2009 was a $1 million gain. A reconciliation of the movements in Risk Management fair values by Level, as well as additional Level III gain (loss) information can be found in Note 4.

C. Inception Gains and Losses

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

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

As at	**March 31, 2009**	Dec. 31, 2008
Unamortized gain at beginning of period	**2**	3
New transactions	**1**	1
Recognized in the Consolidated Statements of Earnings during the period:		
Amortization	**(2)**	(2)
Unamortized gain at end of period	**1**	2

D. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk – Proprietary Trading

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. Value at Risk ("VaR") at March 31, 2009 associated with the Corporation's proprietary trading activities was $5 million (March 31, 2008 - $7 million).

b. Commodity Price Risk - Generation

VaR at March 31, 2009 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $60 million (March 31, 2008 - $74 million).

The Corporation's policy on asset-backed transactions is to seek normal purchase / normal sale ("NPNS") contract status or hedge accounting treatment. Where this is not possible, the transactions are marked to the market value. These include, for example, positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions such as buybacks entered into to offset existing hedge positions. Changes in market prices associated with these transactions affect net earnings in the period in which the price change occurs. VaR at March 31, 2009 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was $1 million (March 31, 2008 - $3 million).

c. Interest Rate Risk

The possible effect on pre-tax earnings and Other Comprehensive Income ("OCI"), due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading interest rate and other hedging derivatives outstanding at the Consolidated Balance Sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is the most reasonably possible change in market interest rates over the next quarter and is consistent with a +/- one standard deviation move from the mean.

	3 months ended March 31			
	2009		2008	
	Pre-tax earnings increase [1]	**OCI loss[1]**	Pre-tax earnings increase [1]	OCI loss[1]
50 basis point change	1	(3)	1	(4)

[1] This calculation assumes a decrease in market interest rates. An increase would have the opposite effect. Amounts presented are pre-tax.

d. Currency Rate Risk

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

The possible effect on pre-tax earnings and OCI, due to changes in the exchange rates associated with financial instruments outstanding at the Consolidated Balance Sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is the most reasonably possible change over the next quarter and is consistent with a +/- one standard deviation move from the mean.

	3 months ended March 31			
	2009		2008	
Currency	**Pre-tax earnings decrease [1]**	**OCI gain[1]**	Pre-tax earnings decrease [1]	OCI gain[1]
Euro	-	4	-	3
U.S.	(4)	3	-	-
AUD	(3)	-	(4)	3
Total	(7)	7	(4)	6

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

II. Credit Risk

At March 31, 2009, TransAlta did not have any counterparties whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at the end of the three month period.

The Corporation's maximum exposure to credit risk at March 31, 2009 and at Dec. 31, 2008, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading, at March 31, 2009 was $76 million (Dec. 31, 2008 - $105 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for counterparties. The following table outlines the distribution, by credit rating, of financial assets as at March 31, 2009:

	Investment grade	**Non-investment grade**	**Total**
	%	**%**	**%**
Accounts receivable	89	11	100
Risk management assets	98	2	100

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

As at	**March 31, 2009**	Dec. 31, 2008
Allowance at beginning of period	**57**	46
Change in foreign exchange rates	**1**	11
Allowance at end of period	**58**	57

At March 31, 2009, the Corporation did not have any significant past due amounts, except as disclosed in Note 19.

III. Liquidity Risk

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

	2009	**2010**	**2011**	**2012**	**2013**	**2014 and thereafter**	**Total**
Short-term debt	377	-	-	-	-	-	377
Accounts payable and accrued liabilities	434	-	-	-	-	-	434
Collateral received	219	-	-	-	-	-	219
Long-term debt [1]	242	33	255	409	408	1,064	2,411
Energy Trading risk management assets [2]	(133)	(117)	(87)	(73)	(6)	-	(416)
Other risk management (assets) liabilities [3]	(22)	(1)	(11)	-	-	27	(7)
Interest on short- and long-term debt	121	148	137	115	100	570	1,191
Total	1,238	63	294	451	502	1,661	4,209

[1] *Excludes impact of derivatives.*

[2] *Energy Trading risk management assets are comprised of net risk management assets and liabilities, where the net result is an asset.*

[3] *Other risk management assets and liabilities are comprised of net risk management assets and liabilities, where the net result is an asset.*

E. Financial Instruments Provided as Collateral

At March 31, 2009, $70 million (Dec. 31, 2008 - $63 million) of financial assets, consisting of bank accounts and accounts receivable, related to the Corporation's proportionate share of CE Generation, LLC ("CE Gen") have been pledged as collateral for certain CE Gen debt. Should any defaults occur, the debt-holders would have first claim on these assets.

F. Financial Assets Held as Collateral

At March 31, 2009, the Corporation had received $219 million (Dec. 31, 2008 - $24 million) in collateral associated with counterparty obligations. Under the terms of the contract, the Corporation is obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

G. Financial Assets Provided as Collateral

At March 31, 2009, the Corporation provided $28 million (Dec. 31, 2008 - $37 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

H. Gains and Losses on Financial Instruments

The Corporation's Commercial Operations & Development ("COD") segment utilizes a variety of derivatives in its proprietary trading activities including commodity hedging activities, and other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the three months ended March 31, 2009, the COD segment recognized $15 million (March 31, 2008 - $15 million) of net realized and unrealized gains *(Note 21)*.

Net interest expense as reported on the Consolidated Statements of Earnings includes interest income and expense, respectively, on the Corporation's interest-bearing financial assets, primarily cash and restricted cash, and its interest-bearing financial liabilities, primarily short- and long-term debt. Interest expense is calculated using the effective interest rate method *(Note 8)*. Interest rate derivatives that are not designated as hedges are classified as held for trading and are marked-to-market each reporting period with the net gain or loss recorded in net interest expense.

Foreign exchange derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss on Energy Trading derivatives recorded in revenue, and the net gain or loss on other foreign exchange derivatives recorded in foreign exchange gain or loss on the Consolidated Statements of Earnings.

Other derivatives that are not designated as hedges are also classified as held for trading, with the net gain or loss recorded in operations, maintenance, and administration expense. Other derivatives consist of a total return swap that fixes the settlement cost of certain employee compensation and deferred share unit programs. The total return swap is cash settled every quarter.

The table below summarizes the net losses included in net earnings that are associated with derivatives not designated as hedges:

	3 months ended March 31	
	2009	2008
Foreign exchange derivatives losses	**5**	1
Other derivatives losses	**3**	-

4. RISK MANAGEMENT ASSETS AND LIABILITIES

Aggregate risk management assets and liabilities are as follows:

As at	March 31, 2009			Dec. 31, 2008		
Balance Sheet - Totals	**Energy Trading**	**Other**	**Total**	Energy Trading	Other	Total
Risk management assets						
Current	**269**	**27**	**296**	176	24	200
Long-term	**275**	**32**	**307**	187	34	221
Risk management liabilities						
Current	**108**	**6**	**114**	142	6	148
Long-term	**20**	**46**	**66**	57	45	102
Net risk management assets	**416**	**7**	**423**	164	7	171

Energy Trading

The risk management assets and liabilities related to Energy Trading are as follows:

As at	March 31, 2009			Dec. 31, 2008
Balance Sheet - Energy Trading	**Hedges**	**Non-hedges**	**Total**	Total
Risk management assets				
Current	**177**	**92**	**269**	176
Long-term	**275**	**-**	**275**	187
Risk management liabilities				
Current	**24**	**84**	**108**	142
Long-term	**14**	**6**	**20**	57
Net risk management assets	**414**	**2**	**416**	164

The following table summarizes the key factors impacting the fair value of the Corporation's Energy Trading net risk management assets and liabilities separately by source of valuation during the three months ended March 31, 2009:

	Hedges			Non-hedges			Total		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets at Dec. 31, 2008	-	163	-	1	-	-	1	163	-
Changes attributable to:									
Commodity price changes	-	249	-	-	(1)	-	-	248	-
New contracts entered during the period	-	6	-	-	1	1	-	7	1
Contracts settled during the period	-	(11)	-	-	(2)	2	-	(13)	2
Change in foreign exchange rates	-	7	-	-	-	-	-	7	-
Transfers in/out of Level III	-	3	(3)	-	-	-	-	3	(3)
Net risk management assets (liabilities) at March 31, 2009	**-**	**417**	**(3)**	**1**	**(2)**	**3**	**1**	**415**	**-**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			-			-			-
Change in fair value included in earnings before income taxes			(3)			3			-
Change in fair value included in earnings before income taxes relating to those net assets (liabilities) held at March 31, 2009			-			1			1

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

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

		2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	132	119	87	73	6	-	**417**
	Level III	(1)	(2)	-	-	-	-	**(3)**
Non-hedges	Level I	1	-	-	-	-	-	**1**
	Level II	(2)	-	-	-	-	-	**(2)**
	Level III	3	-	-	-	-	-	**3**
Total by level	Level I	1	-	-	-	-	-	**1**
	Level II	130	119	87	73	6	-	**415**
	Level III	2	(2)	-	-	-	-	**-**
Total net assets		**133**	**117**	**87**	**73**	**6**	**-**	**416**

The Corporation's outstanding Energy Trading derivative financial instruments at March 31, 2009 are summarized below:

Units (000s)	Electricity (MWh)	Natural gas (GJ)	Transmission (MWh)	Coal (tonnes)	Emissions (tonnes)	Oil (gallons)
Derivative financial instruments designated as hedges						
Notional Amounts						
Purchases	-	2,991	-	-	-	25,074
Sales	25,405	-	-	-	-	-
Derivative financial instruments held for trading (non-hedges)						
Notional Amounts						
Purchases	22,474	187,347	660	295	70	825
Sales	22,217	180,425	-	295	70	-

Other Risk Management Assets and Liabilities

The non-Energy Trading risk management assets and liabilities included in the Consolidated Balance Sheets are as follows:

As at	March 31, 2009			Dec. 31, 2008
Balance Sheet - Other	**Hedges**	**Non-hedges**	**Total**	Total
Risk management assets				
Current	**25**	**2**	**27**	24
Long-term	**32**	**-**	**32**	34
Risk management liabilities				
Current	**4**	**2**	**6**	6
Long-term	**46**	**-**	**46**	45
Net risk management assets	**7**	**-**	**7**	7

The following table summarizes the key factors impacting the fair value of the Corporation's other net risk management assets and liabilities during the three months ended March 31, 2009:

	Hedges[1]	Non-hedges[1]	Total
Net risk management assets (liabilities) at Dec. 31, 2008	8	(1)	7
Changes attributable to:			
Commodity price changes	(5)	1	(4)
New contracts entered during the period	(41)	(2)	(43)
Contracts settled during the period	45	2	47
Net risk management assets at March 31, 2009	**7**	**-**	**7**

[1] *Consistent with industry practices, all other risk management assets and liabilities are classified in Level II.*

Changes in net risk management assets and liabilities for hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. So as long as these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument or reduction in the net investment in the foreign operations.

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

	2009	2010	2011	2012	2013	2014 and thereafter	Total
Hedges	22	1	11	-	-	(27)	**7**
Non-hedges	-	-	-	-	-	-	**-**
Total net assets (liabilities)	**22**	**1**	**11**	**-**	**-**	**(27)**	**7**

Additional information related to the hedges and non-hedges of other risk management assets are outlined below:

A. Hedges

I. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$1,100 million (Dec. 31, 2008 – U.S.$1,100 million), and U.S. dollar denominated short -term debt with a face value of U.S.$238 million (Dec. 31, 2008 – U.S.$238 million) has been designated as a part of the hedge of TransAlta's net investment in self-sustaining foreign operations.

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

a. Cross-Currency Interest Rate Swap

Outstanding cross-currency interest rate swap is as follows:

March 31, 2009			Dec. 31, 2008		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
AUD34	**1**	**2009**	AUD34	2	2009

b. Foreign Currency Contracts

Outstanding foreign currency forward sales contracts are as follows:

March 31, 2008			Dec. 31, 2008		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD108	**-**	**2009**	AUD108	1	2009
U.S.(287)	**3**	**2009**	U.S.(107)	1	2009

II. Hedges of Future Foreign Currency Obligations

TransAlta's future foreign currency obligations are primarily related to foreign denominated capital asset purchases. The Corporation has hedged a portion of these obligations through forward purchase contracts as follows:

March 31, 2009				Dec. 31, 2008			
Amount sold	**Amount purchased**	**Fair value asset**	**Maturity**	Amount sold	Amount purchased	Fair value asset	Maturity
104	**U.S.90**	**9**	**2009-2010**	51	U.S.48	8	2009-2010
U.S.2	**2**	**-**	**2009**	-	-	-	n/a
85	**EUR57**	**9**	**2009**	84	EUR57	13	2009

III. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 6.6 per cent to 6.9 per cent, to floating rate debt through interest rate swaps as shown below:

March 31, 2009			Dec. 31, 2008		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
100	**11**	**2011**	100	12	2011
U.S.100	**20**	**2018**	U.S.100	21	2018

Including the interest rate swaps above, 22 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2008 - 24 per cent).

The Corporation also has an outstanding forward start interest rate swap that converts floating rate debt into fixed rate debt, with fixed rates ranging from 3.5 per cent to 4.6 per cent, as shown below:

March 31, 2009			Dec. 31, 2008		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
U.S.300	**46**	**2020**	U.S.300	46	2019

B. Non-Hedges

I. Cross-Currency Interest Rate Swaps

Cross-currency interest rate swaps are periodically entered into in order to limit the Corporation's exposure to fluctuations in market interest rates. These outstanding cross-currency interest rate swaps are as follows:

March 31, 2009			Dec. 31, 2008		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
AUD41	**2**	**2009**	AUD41	1	2009

II. Held for Trading and Total Return Swaps

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

Outstanding notional amounts and fair values of held for trading financial instruments are as follows:

March 31, 2009			Dec. 31, 2008		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD22	**2**	**2009**	-	-	n/a
U.S.71	**-**	**2009**	U.S.90	2	2009

The Corporation also has certain compensation and deferred share units programs the value of which depend on the common share price of the Corporation. The Corporation has fixed the settlement cost of these programs by entering into a total return swap. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price at the end of each quarter.

C. Contingent Features in Derivative Instruments

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

As at March 31, 2009 the Corporation had posted collateral of $104 million in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at March 31, 2009, the Corporation would be required to post an additional $62 million of collateral to its counterparties.

5. HEDGING ACTIVITIES

Fair Value Hedges

Interest rate swaps are used to hedge exposures to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates.

No ineffective portion of fair value hedges was recorded for the three months ended March 31, 2009 and March 31, 2008.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings for the three months ended March 31, 2009:

Derivatives in fair value hedging relationships	Location of gain (loss) on statements of earnings	Total
Interest rate contracts	Interest expense	**2**
Long-term debt	Interest expense	**(2)**
Net earnings impact		**-**

Cash Flow Hedges

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

For the three months ended March 31, 2009, a pre-tax unrealized gain of $280 million (March 31, 2008 - pre-tax unrealized loss of $229 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $38 million (March 31, 2008 - $17 million) in amounts previously related to OCI was reclassified to net earnings. For the three months ended March 31, 2009 and March 31, 2008 no realized gains or losses were recognized in earnings for the ineffective portion.

Over the next 12 months, the Corporation estimates that $111 million (Dec. 31, 2008 - $17 million) of after-tax losses will be reclassified from Accumulated Other Comprehensive Income ("AOCI") to net earnings.

The following table summarizes the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets for the three months ended March 31, 2009:

Derivatives in cash flow hedging relationships	Gains (loss) recognized in OCI [1]	Location of gain (loss) reclassified from OCI	Pre-tax losses reclassified from OCI [1]
Interest rate contracts	**(1)**	Interest expense	**-**
Foreign exchange contracts	**1**	Foreign exchange gain (loss)	**-**
		Property, plant, and equipment	**(4)**
Commodity contracts	**280**	Revenue	**(38)**
OCI impact	**280**	**OCI impact**	**(42)**

Net Investment Hedges

For the three months ended March 31, 2009, a net after-tax gain of $19 million (March 31, 2008 - loss of $5 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the impact of net investment hedges on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Earnings for the three months ended March 31, 2009:

Derivatives in net investment hedging relationships	Losses recognized in OCI
Short-term debt	(9)
Long-term debt	(41)
OCI impact	**(50)**

Summary

The following table summarizes the fair values of derivative instruments categorized by their hedging relationships, as well as derivatives that are not designated as hedges:

As at	March 31, 2009					Dec. 31, 2008
	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated in a hedging relationship	Total	Total
Financial derivative assets	31	470	8	94	603	421
Financial derivative liabilties	-	84	4	92	180	250

6. INVENTORY

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

As at	March 31, 2009	Dec. 31, 2008
Coal	54	45
Natural gas	3	5
Purchased emission credits	-	1
Total	**57**	51

The increase in coal inventory at March 31, 2009 compared to Dec. 31, 2008 is primarily due to lower production at the Alberta Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2008	51
Net additions	5
Change in foreign exchange rates	1
Balance, March 31, 2009	**57**

No inventory is pledged as security for liabilities.

For the three months ended March 31 2009, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into earnings.

7. INCOME TAX EXPENSE

The components of income tax expense are as follows:

	3 months ended March 31	
	2009	2008
Current tax (recovery) expense	**(15)**	30
Future income tax expense (recovery)	**19**	(16)
Income tax expense	**4**	14

8. LONG-TERM DEBT AND NET INTEREST EXPENSE

As at	**March 31, 2009**			Dec. 31, 2008		
	Carrying value	**Cost**	**Interest [1]**	Carrying value	Cost	Interest [1]
Debentures	**671**	**681**	**6.8%**	682	681	6.8%
Senior notes (2009 - U.S.$1,100 million, 2008 - U.S.$1,100 million)	**1,405**	**1,386**	**6.3%**	1,352	1,344	6.3%
Non-recourse	**271**	**271**	**7.4%**	265	265	7.4%
Other	**64**	**64**	**5.9%-7.4%**	66	66	5.9%-7.4%
	2,411	**2,402**		2,365	2,356	
Less: current portion	**(245)**	**(245)**		(244)	(244)	
Total long-term debt	**2,166**	**2,157**		2,121	2,112	

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

The Corporation has converted $100 million fixed interest rate debt with a rate of 6.6 per cent to floating rates through the use of interest rate swaps. These interest rate swaps mature in June 2011 *(Note 4)*.

The Corporation has converted U.S.$100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of interest rate swaps. These interest rate swaps mature in March 2018 *(Note 4)*.

The components of net interest expense are as follows:

	3 months ended March 31	
	2009	2008
Interest on long-term debt	**39**	32
Interest on short-term debt	**4**	10
Interest income	**(2)**	(5)
Capitalized interest	**(8)**	(4)
Net interest expense	**33**	33

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

9. ASSET RETIREMENT OBLIGATIONS

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

Balance, Dec. 31, 2008	297
Liabilities incurred in period	1
Liabilities settled in period	(8)
Accretion expense	6
Change in foreign exchange rates	2
	298
Less current portion	(48)
Balance, March 31, 2009	**250**

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

10. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

During the first quarter of 2009, TransAlta settled a $7 million previously provided for commercial item.

11. OTHER INCOME

In 2009, the Corporation settled an outstanding commercial issue for a pre-tax gain of $7 million. In 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million.

12. NON-CONTROLLING INTERESTS

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2008	469
Distributions paid	(16)
Non-controlling interest portion of net earnings	14
As at March 31, 2009	**467**

13. 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, 2009, the Corporation had 197.8 million (Dec. 31, 2008 - 197.6 million) common shares issued and outstanding. During the three months ended March 31, 2009, 0.2 million shares (March 31, 2008 - 0.4 million) were issued for proceeds of nil (March 31, 2008 - $11 million). In 2009, the shares issued were pursuant to the Corporation's Performance Share Ownership Plan and, therefore did not result in any cash proceeds.

During the three months ended March 31, 2009, no shares (March 31, 2008 - 1.9 million) were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program.

B. Stock options

At March 31, 2009, the Corporation had 1.6 million outstanding employee stock options (Dec. 31, 2008 - 1.7 million). For the three months ended March 31, 2009, no options were exercised or cancelled, and 0.1 million options expired. For the three months ended March 31, 2008, 0.2 million options with a weighted average exercise price of $20.81 were exercised resulting in 0.2 million shares issued, and no options were cancelled.

For the three months ended March 31, 2009, the total amount related to stock options recorded in operations, maintenance, and administration expense was $0.7 million.

14. SHAREHOLDERS' EQUITY

	Common shares	Retained earnings	Accumulated Other Comprehensive Income	Total shareholders' equity
Balance, Dec. 31, 2008	1,761	688	61	2,510
Net earnings	-	42	-	42
Common shares issued (dividends declared)	6	(57)	-	(51)
Gains on translating financial statements of self-sustaining foreign operations, net of tax	-	-	19	19
Gains on derivatives designated as cash flow hedges, net of tax	-	-	189	189
Derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net earnings in the current period	-	-	(27)	(27)
Balance, March 31, 2009	**1,767**	**673**	**242**	**2,682**

The components of AOCI are presented below:

As at	March 31, 2009	Dec. 31, 2008
Cumulative unrealized gains (losses) on translating financial statements of self-sustaining foreign operations, net of tax	**12**	(7)
Cumulative unrealized gains on cash flow hedges, net of tax	**230**	68
Accumulated other comprehensive income	**242**	61

Normal Course Issuer Bid Program

On May 5, 2008, TransAlta announced plans to renew the NCIB program until May 5, 2009. The Corporation received the approval to purchase, for cancellation, up to 19.9 million of its common shares representing 10 per cent of the 199 million common shares issued and outstanding as at April 23, 2008. Any purchases undertaken will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

Details of the share purchases under the Corporation's NCIB program are as follows:

	3 months ended March 31	
	2009	**2008**
Total shares purchased	**-**	1,908,900
Average purchase price per share	**-**	31.43
Total cost	**-**	60
Weighted average book value of shares cancelled	**-**	17
Reduction to retained earnings	**-**	43

15. CAPITAL

TransAlta's capital is comprised of the following components:

As at	March 31, 2009	Dec. 31, 2008	(Decrease)/ increase
Short-term debt including current portion of long-term debt	**622**	687	(65)
Less: cash and cash equivalents	**(49)**	(50)	1
	573	637	(64)
Long-term debt			
Recourse	**1,927**	1,889	38
Non-recourse	**239**	232	7
Non-controlling interests	**467**	469	(2)
Common shareholders' equity			
Common shares	**1,767**	1,761	6
Retained earnings	**673**	688	(15)
AOCI	**242**	61	181
	5,315	5,100	215
Total capital	**5,888**	5,737	151

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2008.

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

	March 31, 2009	Dec. 31, 2008	Target
Cash flow to interest (times)	**6.6**	7.2	Minimum of 4
Cash flow to total debt (%)	**29.9**	31.1	Minimum of 25
Debt to invested capital (%)	**46.5**	48.1	Maximum of 55

During the first quarter of 2009, net cash outflows from operating activities, after dividends and capital asset additions, are summarized below:

	3 months ended March 31		
	2009	2008	(Decrease)/ increase
Cash flow from operating activities	**83**	237	(154)
Dividends paid	**(54)**	(51)	(3)
Capital asset expenditures	**(131)**	(150)	19
Net cash (outflow) inflow	**(102)**	36	(138)

For the three months ended March 31, 2009 the decrease in the total net cash flows primarily resulted from lower earnings, and less favourable working capital movements primarily related to the timing of power purchase agreement payments. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business.

The financial terms and conditions of the Corporation's debentures and credit facilities remain unchanged from Dec. 31, 2008.

TransAlta's formal dividend policy has remained unchanged from Dec. 31, 2008.

16. RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership with Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and EPCOR Power Development Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at March 31, 2009, TAGP had received $44 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the first quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when operations commence.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The values of these contracts are U.S.$3 million for the years ending Dec. 31, 2009 and 2010.

For the period November 2002 to November 2012, one of TransAlta's subsidiaries, TA Cogen, entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for three of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to 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 and therefore has no risk other than counterparty risk.

17. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware, when taken as a whole, will have a material adverse effect on the Corporation.

18. COMMITMENTS

On Jan. 29, 2009, TransAlta announced two efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded by 23 MW each, to a total of 450 MW and are expected to be operational by the end of 2011 and 2012, respectively. The capital cost of the projects is estimated at $68 million.

Natural Forces Technologies Inc. has provided the Corporation with a written notice of its election to exercise the option to purchase 17 percent of the Kent Hills project for approximately $30 million. Natural Forces Technologies Inc. can exercise its option up to June 2, 2009.

19. PRIOR PERIOD REGULATORY DECISION

There have been no changes or developments to the amount provided by the Corporation with respect to refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange and the California Independent System Operator since Dec. 31, 2008.

20. GUARANTEES – LETTERS OF CREDIT

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not pay amounts due under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Balance Sheets. The letters of credit do not contain recourse provisions nor does the Corporation hold any assets as collateral against the guarantees issued. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at March 31, 2009 totalled $374 million (Dec. 31, 2008 - $430 million) with no (Dec. 31, 2008 - nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.2 billion (Dec. 31, 2008 - $2.2 billion) of committed credit facilities of which $1.5 billion (Dec. 31, 2008 - $1.4 billion) is not drawn and is available as of March 31, 2009, subject to customary borrowing conditions.

21. SEGMENTED DISCLOSURES

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

3 months ended March 31, 2009	Generation	COD	Corporate	Total
Revenues	**741**	**15**	**-**	**756**
Fuel and purchased power	**(375)**	**-**	**-**	**(375)**
	366	**15**	**-**	**381**
Operations, maintenance, and administration	**146**	**6**	**22**	**174**
Depreciation and amortization	**111**	**1**	**5**	**117**
Taxes, other than income taxes	**5**	**-**	**-**	**5**
Intersegment cost allocation	**8**	**(8)**	**-**	**-**
	270	**(1)**	**27**	**296**
	96	**16**	**(27)**	**85**
Foreign exchange gain				**1**
Net interest expense *(Note 8)*				**(33)**
Other income *(Note 11)*				**7**
Earnings before non-controlling interests and income taxes				**60**

3 months ended March 31, 2008	Generation	COD	Corporate	Total
Revenues	788	15	-	803
Fuel and purchased power	(370)	-	-	(370)
	418	15	-	433
Operations, maintenance, and administration	100	10	25	135
Depreciation and amortization	100	-	4	104
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation	7	(7)	-	-
	212	3	29	244
	206	12	(29)	189
Foreign exchange loss				(1)
Net interest expense *(Note 8)*				(33)
Equity loss				(97)
Other income *(Note 11)*				5
Earnings before non-controlling interests and income taxes				63

B. Selected Consolidated Balance Sheet information

As at March 31, 2009	Generation	COD	Corporate	Total
Goodwill	**115**	**30**	**-**	**145**
Total segment assets	**7,213**	**178**	**487**	**7,878**
As at Dec. 31, 2008				
Goodwill	112	30	-	142
Total segment assets	7,110	206	499	7,815

An increase in foreign exchange rates has resulted in a $3 million change in goodwill in a self-sustaining foreign operation.

C. Selected Consolidated Cash Flow information

3 months ended March 31, 2009	**Generation**	**COD**	**Corporate**	**Total**
Capital expenditures	**127**	**-**	**4**	**131**

3 months ended March 31, 2008	Generation	COD	Corporate	Total
Capital expenditures	148	1	1	150

D. Depreciation and amortization on Consolidated Statements of Cash Flows

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

	3 months ended March 31	
	2009	2008
Depreciation and amortization expense on Consolidated Statements of Earnings	**117**	104
Depreciation included in fuel and purchased power	**10**	5
Accretion expense included in depreciation and amortization expense	**(6)**	(5)
Other	**-**	3
Depreciation and amortization on Consolidated Statements of Cash Flows	**121**	107

22. EMPLOYEE FUTURE BENEFITS

Costs recognized in the period are presented below:

3 months ended March 31, 2009	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**1**	**-**	**-**	**1**
Interest cost	**5**	**1**	**1**	**7**
Actual return on plan assets	**(5)**	**-**	**-**	**(5)**
Actuarial loss	**1**	**-**	**-**	**1**
Amortization of net transition (asset) obligation	**(2)**	**-**	**-**	**(2)**
Defined benefit expense	**-**	**1**	**1**	**2**
Defined contribution option expense of registered pension plan	**7**	**-**	**-**	**7**
Net expense	**7**	**1**	**1**	**9**

3 months ended March 31, 2008	Registered	Supplemental	Other	Total
Current service cost	1	-	1	2
Interest cost	5	1	-	6
Actual return on plan assets	(6)	-	-	(6)
Amortization of net transition (asset) obligation	(2)	-	-	(2)
Defined benefit (income) expense	(2)	1	1	-
Defined contribution option expense of registered pension plan	5	-	-	5
Net expense	3	1	1	5

23. SUBSEQUENT EVENTS

Ardenville Wind Power Project

On April 28, 2009, the Corporation announced plans to design, build, and operate Ardenville, a 72 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Commercial operations are expected to commence in the first quarter of 2011.

SUPPLEMENTAL INFORMATION

		March 31, 2009	Dec. 31, 2008
Closing market price (TSX) ($)		**18.45**	24.30
Price range for the last 12 months (TSX) ($)	High	**37.50**	37.50
	Low	**18.11**	21.00
Debt to invested capital including non recourse debt (%)		**46.5**	48.1
Debt to invested capital excluding non recourse debt (%)		**43.9**	45.6
Return on common shareholders' equity (%)		**10.2**	9.8
Comparable return on common shareholders' equity[1, 2] (%)		**9.5**	12.1
Return on capital employed[1] (%)		**7.8**	7.8
Comparable return on capital employed[1, 2] (%)		**8.3**	9.8
Cash dividends per share[1] ($)		**1.10**	1.08
Price/earnings ratio[1] (times)		**14.9**	20.6
Earnings coverage[1] (times)		**2.7**	2.8
Dividend payout ratio based on net earnings[1] (%)		**89.3**	91.5
Dividend payout ratio based on comparable earnings[1, 2] (%)		**96.0**	74.1
Dividend coverage[1] (times)		**4.1**	4.8
Dividend yield[1] (%)		**6.0**	4.4
Cash flow to debt[1] (%)		**29.9**	31.1
Cash flow to interest coverage (times)[1]		**6.6**	7.2

1 Annualized

2 These ratios incorporate items that are not defined under Canadian GAAP. None of these measurements are used to enhance the Corporation's reported financial performance or position. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application.

RATIO FORMULAS

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

Return on common shareholders' equity = net earnings or comparable earnings / average of opening and closing common shareholders' equity

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

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

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

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

Dividend payout ratio = dividends / net earnings or comparable earnings

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

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

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

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

GLOSSARY OF KEY TERMS

Alberta Power Purchase Agreement (PPA) - A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA Buyers.

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

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

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

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

Cogeneration - A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

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.

Greenhouse Gas (GHG) – Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

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

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

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

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

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

Unplanned Outage - The shutdown of a generating unit due to an unanticipated breakdown.

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

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

TransAlta Corporation
Box 1900, Station “M”
110 - 12th Avenue S.W.
Calgary, Alberta Canada T2P 2M1
Phone
403.267.7110

Website
www.transalta.com

CIBC Mellon Trust Company
P.O. Box 7010 Adelaide Street Station
Toronto, Ontario Canada M5C 2W9
Phone
Toll-free in North America: 1.800.387.0825
Toronto or outside North America: 416.643.5500
Fax
416.643.5501
Website
www.cibcmellon.com

FOR MORE INFORMATION

Media inquiries
Michael Lawrence
Manager, External Relations
Phone
403.267.7330
E-mail
media_relations@transalta.com

Investor inquiries
Jennifer Pierce, MA, MBA
Vice-President, Communications and Investor Relations
Phone
1.800.387.3598 in Canada and United States
or 403.267.2520
Fax
403.267.2590
E-mail
investor_relations@transalta.com