TransAlta Corporation

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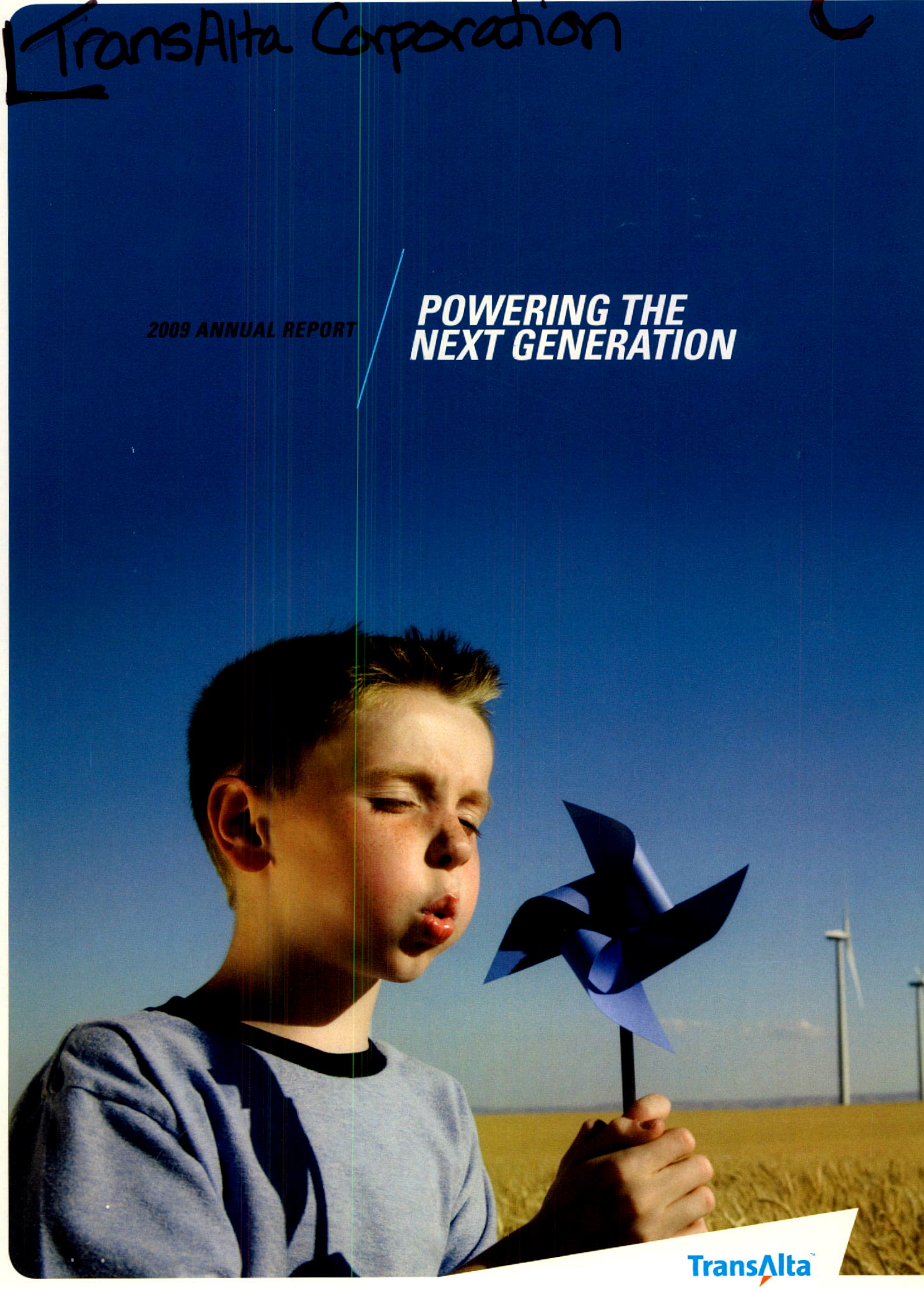
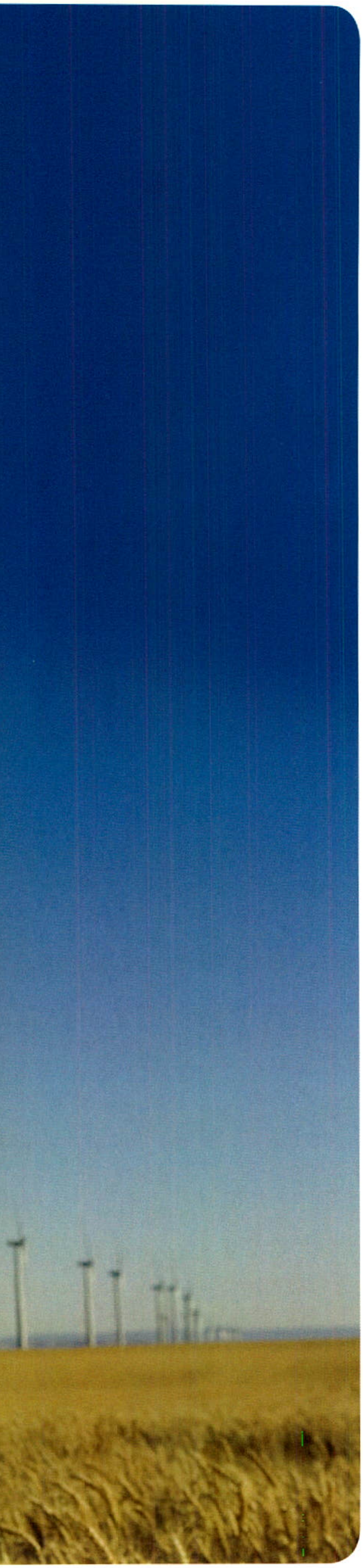


2009 ANNUAL REPORT

POWERING THE NEXT GENERATION

TransAlta™



FINANCIAL HIGHLIGHTS

In millions of Canadian dollars except per common share data and ratios

Year ended Dec. 31	2009	2008	2007
Revenues	$ 2,770	$ 3,110	$ 2,775
Net earnings	$ 181	$ 235	$ 309
Comparable earnings	$ 181	$ 290	$ 264
Cash flow from operations	$ 580	$ 1,038	$ 847
Free cash flow (deficiency)	$ (117)	$ 121	$ 111
Per common share data			
Net earnings	$ 0.90	$ 1.18	$ 1.53
Comparable earnings	$ 0.90	$ 1.46	$ 1.31
Dividends	$ 1.16	$ 1.08	$ 1.00
Ratios			
Cash flow to interest coverage (times)	4.9	7.2	6.6
Cash flow to debt (%)	20.1	31.1	30.7
Debt to invested capital (%)	56.1	48.1	46.8
Comparable return on capital employed (%)	5.8	9.6	9.7

Steve Snyder
President & CEO

By all measures 2009 was a year of large contrasts for TransAlta. We had significant successes that will help drive our company in the years ahead, including the long-term recontracting of our Sarnia plant, the acquisition of Canadian Hydro Developers, and securing funding for Project Pioneer, one of the world's first and largest-scale retrofit carbon capture and storage (CCS) demonstration facilities.

We also had disappointing financial results. Market conditions were extremely challenging. Electricity prices were at 2005 levels, power demand at 2007 rates, and we had a 2009 cost structure. These external impacts were made worse by below-historical performance at our Alberta coal plants, that caused us to miss our targeted availability levels. Strong performance on this key operating parameter is critical for our profitability.

$1.9 billion *invested in renewable energy to significantly advance the greening of our portfolio* / **22%** *of our total generation*

Turning that performance around required significant adjustments to our major maintenance plans. It's not a quick fix. But by year-end the work our teams did was starting to show positive results. While too late for 2009, we will go into 2010 with much better run rates. And, throughout the Corporation we aggressively tackled our cost structure to help not only in 2009, but more importantly on a go-forward basis. We do not see a quick industry recovery and it's important that our base costs are aligned with this new reality.

Our company is entering 2010 in strong shape and very well positioned for the opportunities ahead of us.

We have a very focused and disciplined strategy. We want to grow our renewables portfolio across Canada. We are already by far Canada's largest publicly traded wind energy producer. We will focus the rest of our growth in western Canada and western United States where we already have a strong installed base to build on. Our fuel source growth priorities are geothermal, wind and small scale hydro. We have excellent fuel reserves that we control in all of these categories. Further out, our expertise in natural gas and coal can be brought to bear, once emerging environmental rules and technology advancements are clearer.

Even though 2009 was not as good a year as we wanted, we are entering 2010 with a solid financial base.

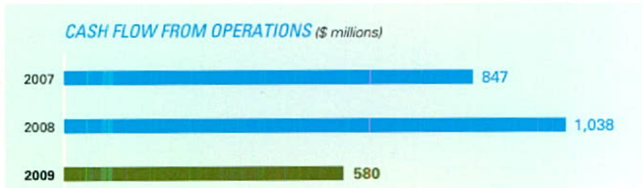
Our company is entering 2010 in strong shape and very well positioned for the opportunities ahead of us.

Our cash flow was and is good. Our balance sheet is in strong shape. We have the resources and capabilities to work our way through the toughest economic cycle we've seen, and to be able to take advantage of growth opportunities when many competitors cannot.

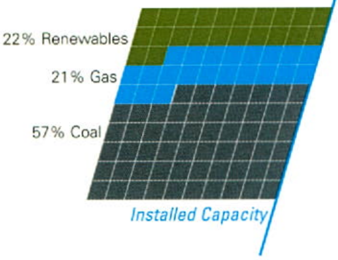
We are continuing to be highly disciplined and focused on our plans. We have three priorities as we go forward.

DRIVE THE BASE. By that we mean improving our plant performance on a sustained basis while also improving productivity to drive down costs. Our goal for 2010 is to equal our best ever fleet availability performance of 90 per cent. Given our performance from our natural gas and renewable assets, and the work we performed on our coal plants last year, we believe this is achievable.

REPOSITION COAL. Emerging environmental targets and policies mean we must adjust over time to a world that is less dependent on coal and to the development and



portfolio consists of renewables



*Over **$770 million** in government funding awarded to TransAlta to advance the development of CCS*

We have the resources and capabilities to work our way through the toughest economic cycle we've seen.

application of new technologies that will enable coal plants to continue to operate in a cost-effective manner. There is no quick fix. Like much of the industry, we have a large infrastructure investment. Coal-based generation represents the lion's share of that investment. It won't be easy to replace that capacity. And it must be done in such a way as to maintain reliability and not be economically disruptive to our customers. The planning must start now. It's a very long life cycle business. We have developed plans that provide excellent optionality for our coal fleet. These multi-year plans also incorporate multiple decision points and off-ramps that allow us to adapt to the changing landscape of environmental policy.

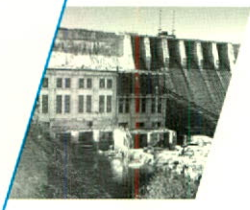
GREEN OUR PORTFOLIO. Our third strategic imperative. We have developed one of the best green growth portfolios in the industry.

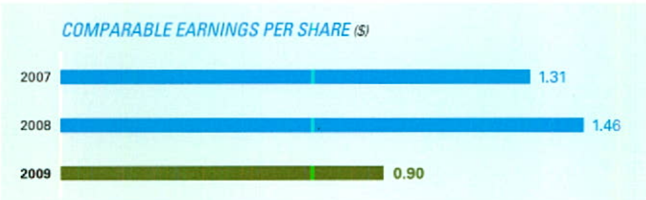
Our customers want more of their electrical needs supplied by generation that produces less CO_2. We've spent the last 10 years developing the fuel reserves and the expertise to do just that. That investment and hard work are now paying off.

We have, in conjunction with our partner CE Gen, one of the best geothermal reserves in North America. We have access to wind resources right across Canada, and especially in southern Alberta which has some of the best resources in North America. We've fundamentally increased our capability to add to our run-of-river hydro portfolio with the acquisition of Canadian Hydro Developers. And, we have the right cost structure and a proven development and construction track record to capitalize on these opportunities. At TransAlta our green power portfolio is good business.

SENIOR MANAGEMENT ***(Standing left to right)***
Dawn Farrell Chief Operating Officer;
Ken Stickland Chief Legal Officer;
Brian Burden Chief Financial Officer
(Sitting left to right)
Mike Williams Chief Administration Officer;
Steve Snyder President & Chief Executive Officer

Over **100 years** of experience—incorporated in 1909 | Approximately **50,000 GWh** produced every year—enough to power over





These three priorities will guide us in the years ahead. Coupled with our financial strength, they give TransAlta a strong focused platform to the future. We'll also stay guided by the key principles we've ingrained into all of our operations and planning: disciplined capital allocation, low-to-moderate risk profile, investment grade credit ratings, a solid and growing dividend and environmental leadership.

The glue holding all this together is our people. Our employees are fully engaged. They've shown over the years that they are resilient, dedicated, and focused on success. All have share ownership, either through stock options at the lower levels or through our share ownership program at more senior levels. We're supported and governed by a strong, experienced Board. They are engaged and proactive in their advice and counsel to management.

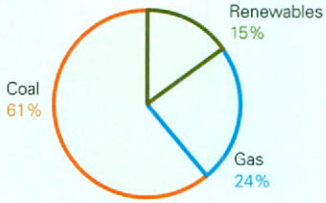
I want to thank each of you, our shareowners, for your loyalty and support. You've supported our equity and debt requirements needed to sustain our fleet capabilities and to grow our company. You understand the long industry cycle environment we work in and our need to manage to that discipline. At the same time, you know we are doing all we can to deliver improved results today and tomorrow.

My thanks to all our stakeholders. By continuing to work together, we'll deliver superb value well into the future.

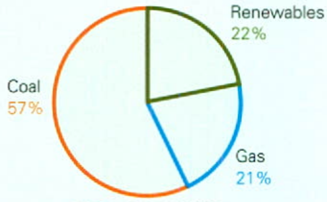
Steve Snyder
President and Chief Executive Officer
March 4, 2010

We have over 100 years of experience along with clear and strategic imperatives in place to power our next generation.

In 2009 we expanded our portfolio to become Canada's leading publicly traded provider of renewable energy.

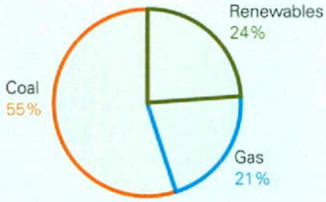


2008 8,073 MW

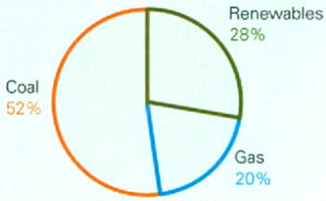


2009 8,776 MW

Expansion of our renewable portfolio will continue to be a priority in years ahead.



2012 8,975 MW



2012e EBITDA

7 million homes

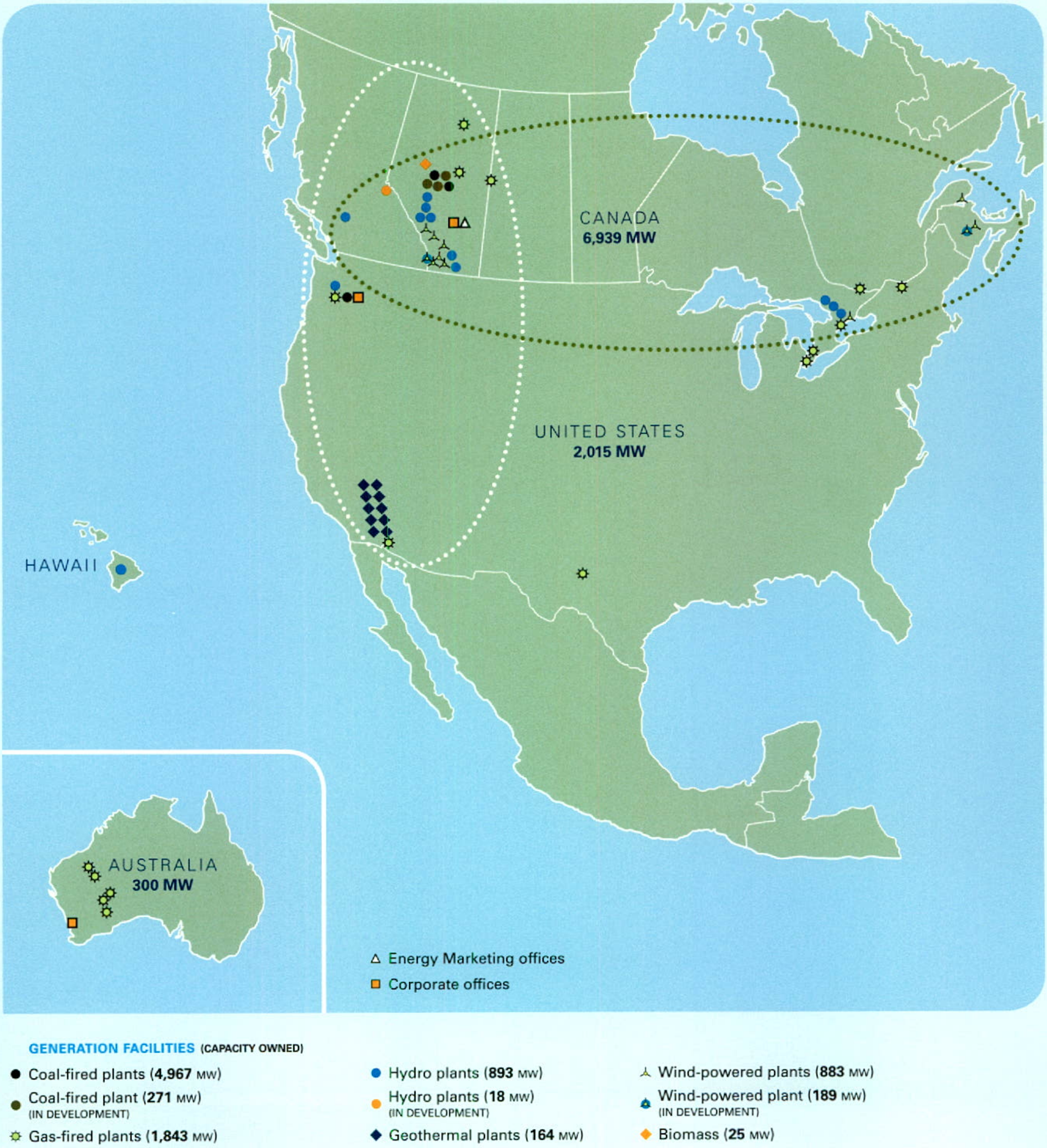
40% of Alberta's total installed capacity is owned by TransAlta

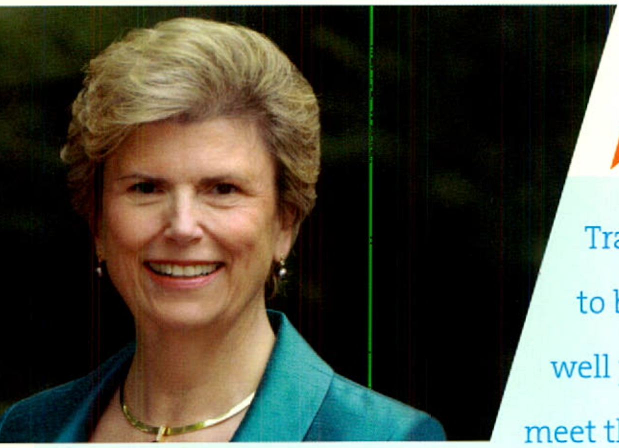
Over 1,900 MW of renewable energy

TransAlta's 2009 Report on Sustainability will be published to www.transalta.com/2009rs in June 2010.

2009 BY THE NUMBERS…

- 1.9 billion invested in renewable energy
- 7 per cent increase in the annual dividend
- 7 per cent increase in TransAlta's renewable energy portfolio (15 per cent to 22 per cent)
- 9 per cent increase in total capacity (8,073 MW to 8,776 MW)
- 81 generating facilities
- 61 per cent five year cumulative total return to shareholders
- 95 per cent contracted
- 100 years of experience





MESSAGE FROM THE CHAIR

Donna Soble Kaufman

TransAlta's Board of Directors is committed to continuing to build a strong and sustainable company—one that is well positioned to power future generations and ready to meet the challenges of our changing times.

2009 was a year of important milestones for TransAlta, marking our 100th anniversary of incorporation and concluding with a transaction that significantly accelerated the growth of our renewable energy portfolio. It was a year in which we addressed our operational challenges at two key plants within our Alberta coal operations. And it was a year in which we once again advanced the long-term, strategic priorities that will allow us to deliver value well into the future.

2009 saw its share of challenges, but we are proud of what we accomplished for our shareowners and for all of the many communities we serve. TransAlta enters this decade as a North American leader in renewable energy, with unparalleled operational and development expertise, a solid growth pipeline, and a strong balance sheet.

POWERING THE NEXT GENERATION.

TransAlta's Board of Directors is committed to continuing to build a strong and sustainable company—one that is well-positioned to power future generations and ready to meet the challenges of our changing times.

To achieve this goal, we focused on three key areas in 2009: our strategic plan, sustainable business practices and, of course, corporate governance.

STRATEGIC PLAN. We have been fully engaged with our management team in developing TransAlta's strategic plan, with a particular focus on risk management and long-term strategic direction. This direction is best exemplified by the acquisition of Canadian Hydro Developers in October 2009. This transaction provides TransAlta shareowners with both near and long-term value. It accelerates the expansion of our renewable portfolio and opens the door to new and exciting opportunities for employees of both companies.

Safe and reliable electricity powers our economies and underpins our quality of life.

More broadly, the Board reviewed and approved plans to restore availability and make substantial investments that will reposition TransAlta's coal fleet in the future. We took a hard look at our capital allocation plans and priorities, and scrutinized the risk factors associated with our business and plans for growth. We came back to where we have been for some time now—reaffirming our long-term, phased approach to investing in growth projects while returning capital to our shareowners. We continued building our enterprise risk management practices across the company, and furthering TransAlta's reputation as a responsible company and a good corporate citizen.

SUSTAINABLE BUSINESS PRACTICES.

We have long believed that companies must deliver more than monetary performance. This belief is partly a function of TransAlta's role in providing an essential service—safe and reliable electricity powers our economies and underpins our quality of life. It is also a reflection of our belief that companies that genuinely address social, ethical and environmental factors as part of their business model enjoy excellent reputations and perform well over time. We were very pleased to see our sustainable business practices recognized once again in 2009.*

* *TransAlta's 2009 Report on Sustainability will be available at www.transalta.com/2009rs in June 2010.*

We have been fully engaged with our management team in developing TransAlta's strategic plan, with a particular focus on risk management and long-term strategic direction. This direction is best exemplified by the acquisition of Canadian Hydro Developers in October 2009.

Of particular note:

- TransAlta was named to the North American Dow Jones Sustainability Index (DJSI North America) for the fourth consecutive year. The DJSI North America selects the top 20 per cent of companies in each industry sector according to sustainability practices out of the 600 largest North American companies. Inclusion in the index is recognition of outstanding sustainability practices. TransAlta is the only Canadian utility represented on the index.
- We were named to the Jantzi list of the 50 most responsible corporations in Canada for 2009. The list is compiled by Jantzi Research Inc., an independent investment research firm that evaluates and monitors the social and environmental performance of companies. Inclusion in the Jantzi list is granted to companies that lead their industries toward sustainability by setting standards for best practice, and demonstrating superior environmental, social and economic performance.

CORPORATE GOVERNANCE. Our efforts around governance did not go unnoticed in 2009, and we received The Conference Board of Canada's Spencer Stuart 2009 National Award for best private sector corporate governance. The Conference Board specifically recognized us for our leadership in managing risk stating: "The Company's Board has been instrumental in ensuring that risk management is both a systematic process and a key element of TransAlta's corporate culture and board decision making."

We are pleased by this recognition, but we know we must continue to earn your trust every day. Strong corporate governance is a key priority because we believe it creates value and we know it is a duty we owe to our shareowners.

Following 10 years of valuable service to TransAlta and its shareowners, Stanley Bright has decided not to seek re-election to our Board of Directors. I would like to take this opportunity to thank Stan for his very valuable service to the TransAlta Board and his many contributions.

On behalf of the Board, I would also like to thank our employees. The TransAlta team is talented, motivated and committed to success. They are more than capable of powering the next generation.

And, I personally would like to thank the Board for their diligence and commitment. We enter 2010 in a position of strength and we are excited about the future.

As always, to our shareowners, thank you for your confidence and continued support.

Donna Kaufman.

Donna Soble Kaufman
Chair of the Board
March 4, 2010

BOARD OF DIRECTORS
(Back Row—left to right)
Stephen Baum; Martha Piper; Tim Faithfull; Donna Soble Kaufman; Kent Jespersen; Bill Anderson; Stanley Bright;
(Front Row—left to right)
Gordon Lackenbauer; Steve Snyder; Michael Kanovsky; Gordon Giffin

For full Board biographies and a comprehensive list of governance committees, please visit www.transalta.com/board

We have eight key performance measures with long-term targets. Our focus on meeting these targets drives our success.

AVAILABILITY AND PRODUCTION

Our goal is to achieve consistent 90 per cent fleet availability and optimize production.

Availability is a key factor in determining revenue in many of our contracts. Availability is the percentage of time a generating unit is capable of running, regardless of whether or not it is generating electricity. As plants need maintenance and occasionally break down, 100 per cent availability over an extended period of time is not achievable.

Production is the amount of electricity generated and is measured in gigawatt hours. It is a significant driver of revenue in certain contracts.

	2007	2008	2009	Target
Availability (%)	87.2	85.8	85.1	90%
Production (GWh)	50,395	48,891	45,736	Optimize

Availability and production targets were not met in 2009 due to:

- Higher planned and unplanned outages at Alberta coal operations
- Higher unplanned outages at Centralia Thermal
- Lower customer demand
- Lower hydro volumes

In 2010, we expect availability across our fleet to average 90 per cent and we expect production to increase due to higher availability and the acquisition of Canadian Hydro Developers.

PRODUCTIVITY

Our goal is to offset the impact of inflation on OM&A.

Managing our maintenance and administration costs is essential to improving the bottom line. Productivity is measured as operations, maintenance, and administration (OM&A) expense per installed megawatt hour (MWh).

	2007	2008	2009	Target
OM&A ($/installed MWh)	7.81	8.61	8.91	Offset Inflation

In 2009, the accelerated major maintenance program drove a three per cent year-over-year increase in OM&A costs per MWh of installed capacity. Excluding the accelerated major maintenance, OM&A costs were held flat to 2008.

In 2010, OM&A costs per MWh of installed capacity are expected to decrease primarily due to lower planned maintenance and an increase in installed capacity.

SUSTAINING CAPITAL EXPENDITURES

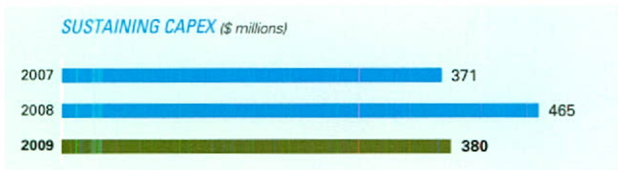
Our goal is to make sustaining capital expenditures more predictable and in line with our long-range plans.

Sustaining capital expenditures are investments made to maintain our current operations. They include routine and major maintenance on our plants, equipment for our mines and investment in our information systems and productivity.

($ millions)	2007	2008	2009	Target
Sustaining Capex	371	465	380	295–340

Sustaining capex spend in 2009 was directly in line with the target of $270–$390 million.

Sustaining capex is anticipated to decline in 2010 as a result of the completion of the Centralia fuel transition and lower major maintenance spend.



EARNINGS

Our target is to generate low double digit EBITDA and comparable EPS growth on an annual basis.

Earnings before interest, tax, depreciation and amortization, is frequently used to analyze and compare profitability between companies and industries because it eliminates the effects of financing and accounting decisions.

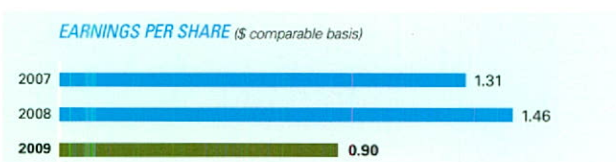
Comparable earnings per share (EPS) is frequently used to measure a company's ongoing profitability.

	2007	2008	2009	Target
EBITDA ($ millions)	980	1,006	895	Low double digit growth
Earnings / share ($) (comparable basis)	1.31	1.46	0.90	Low double digit growth

Earnings decreased in 2009 due to:

- Higher planned and unplanned outages at Alberta coal operations
- Lower hydro volumes and pricing
- Lower energy trading gross margins

Operational improvements and sustainable cost savings are anticipated to drive low double digit EBITDA and EPS growth for 2010.



Our long-term strategy has always been to manage business for all cycles.

CASH FLOW

Our goal is to generate significant cash flow from operations.

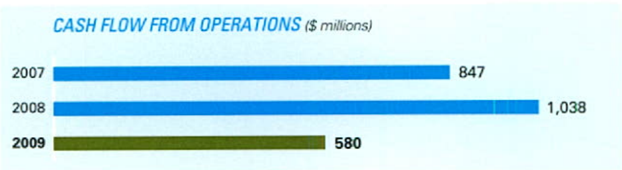
Cash flow generated from operations is used to maintain our equipment, meet our debt repayment obligations, return capital to shareholders through dividends and share buybacks and invest in new capacity.

	2007	2008	2009	Target
Cash from operations ($ millions)	847	1,038	580	850–950

Cash flow from operations decreased in 2009 due to:

- Lower cash earnings
- Receipt of an additional $116 million PPA payment in 2008
- Unfavorable changes in working capital

In 2010, cash flow from operations is anticipated to increase due to increased earnings and the acquisition of Canadian Hydro Developers.



INVESTMENT RATIOS

Our goal is to maintain investment grade credit ratings and operate the business within established financial ratio ranges.

Financial strength and flexibility are critical to the company's ability to create value, capitalize on opportunities and manage industry cyclicality. The ratios used to measure our performance include: cash flow to interest coverage, cash flow to debt, and debt to invested capital. Credit rating agencies also use these ratios when evaluating the financial strength of the company.

	2007	2008	2009	Target
Cash flow to interest coverage (times)	6.6	7.2	4.9	4–5
Cash flow to debt (%)	30.7	31.1	20.1	20–25
Debt to invested capital (%)	46.8	48.1	56.1	55–60

In 2009, we maintained a strong balance sheet, financial ratios, ample liquidity and stable investment grade credit ratings supported by our high level of contracting and low-to-moderate risk business profile.

In 2010, we expect to remain within the ranges that we have established and to maintain our investment grade credit ratings.

SAFETY

Our goal is to achieve an annual injury frequency rate of 1.

Safety is a core value at TransAlta. We take it very seriously and measure ourselves against industry wide standards. Injury Frequency Rate (IFR) measures all fatal, lost time and medical aid injuries.

	2007	2008	2009	Target
Injury Frequency Rate	1.76	1.28	1.41	1 over next 5 yrs

In 2009, we missed our goal of a 10 per cent reduction in the IFR and our overall employee and contractor IFR actually increased over 2008.

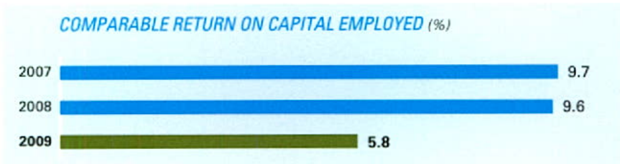
Safety remains a top priority at TransAlta and we have set a five year target to reduce our IFR by 30 per cent.

SUSTAINABLE LONG-TERM SHAREHOLDER VALUE

Our goal is to achieve greater than 10 per cent for both ROCE and TSR on an annual basis.

We also measure returns to our shareholders and investors two ways: comparable return on capital employed (ROCE) and total shareholder return (TSR). ROCE is a measure of the efficiency and profitability of capital investments. TSR is the total amount returned to investors over a specific holding period and includes capital gains or losses, and dividends.

We continue to create economic value from capital investments.



	2007	2008	2009	Target
Comparable ROCE (%)	9.7	9.6	5.8	> 10%
TSR (%)	29.0	(23.9)	1.4	> 10%

Comparable ROCE was lower in 2009, due to increased planned and unplanned outages at Alberta coal operations, lower hydro volumes and prices, lower trading margins and the acquisition of Canadian Hydro Developers.

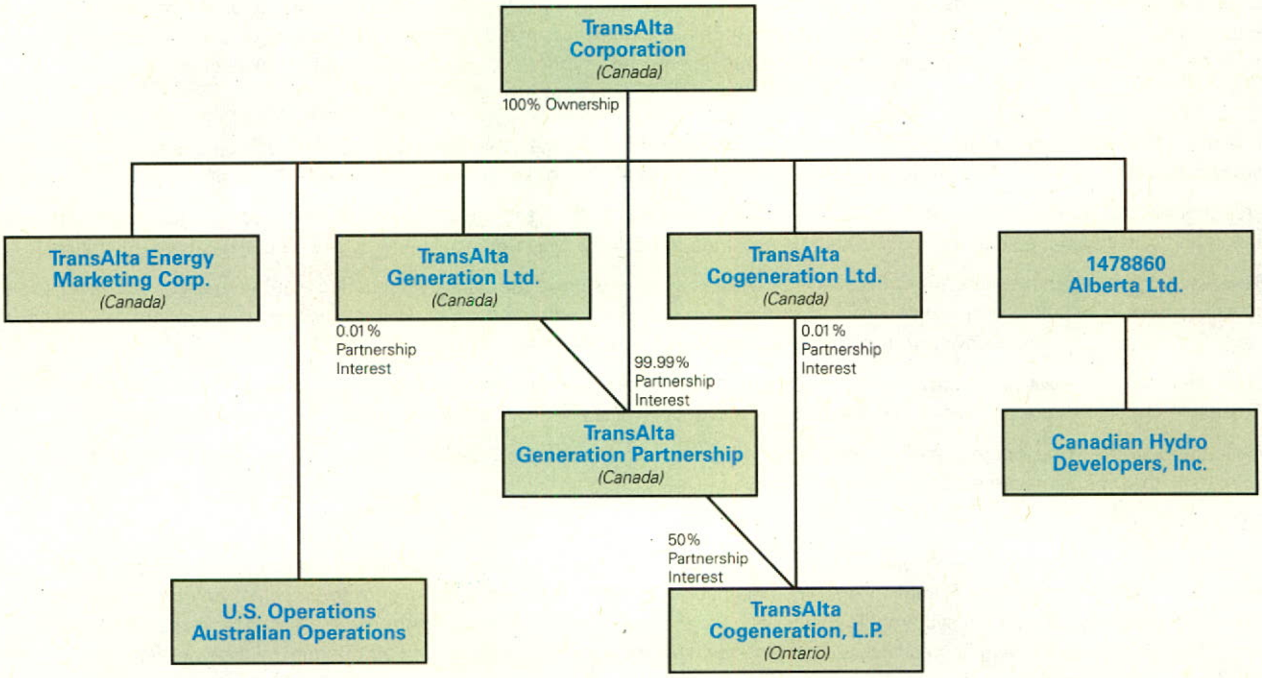
In 2010, comparable ROCE is anticipated to increase due to improved comparable earnings.

Given difficult market conditions throughout the year, TransAlta's TSR was below 10 per cent. Over a five year period our cumulative TSR has been 61 per cent.

PLANT SUMMARY

As of January 31, 2010	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Fuel	Revenue source	Contract expiry date
Western Canada 44 Facilities	Sundance, AB	2,126	100	2,126	Coal	Alberta PPA/Merchant[2]	2017, 2020
	Keephills, AB[3]	812	100	812	Coal	Alberta PPA/Merchant	2020
	Keephills 3, AB[4]	450	50	225	Coal	Merchant	–
	Sheerness, AB	780	25	195	Coal	Alberta PPA	2020
	Wabamun, AB[5]	279	100	279	Coal	Merchant	–
	Genesee 3, AB	450	50	225	Coal	Merchant	–
	Fort Saskatchewan, AB	118	30	35	Gas	LTC	2019
	Meridian, SK	220	25	55	Gas	LTC	2024
	Poplar Creek, AB	356	100	356	Gas	LTC/Merchant	2024
	Barrier, AB	13	100	13	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100	17	Hydro	Alberta PPA	2020
	Belly River, AB	3	100	3	Hydro	Merchant	–
	Big Horn, AB	120	100	120	Hydro	Alberta PPA	2020
	Brazeau, AB	355	100	355	Hydro	Alberta PPA	2020
	Cascade, AB	36	100	36	Hydro	Alberta PPA	2020
	Ghost, AB	51	100	51	Hydro	Alberta PPA	2020
	Horseshoe, AB	14	100	14	Hydro	Alberta PPA	2020
	Interlakes, AB	5	100	5	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100	19	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100	15	Hydro	Alberta PPA	2013
	Rundle, AB	50	100	50	Hydro	Alberta PPA	2020
	Spray, AB	103	100	103	Hydro	Alberta PPA	2020
	St. Mary, AB	2	100	2	Hydro	Merchant	–
	Taylor Hydro, AB	13	50	6	Hydro	Merchant	–
	Three Sisters, AB	3	100	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100	3	Hydro	Merchant	–
	Akolkolex, BC	10	100	10	Hydro	LTC	2015
	Pingston, BC	45	50	23	Hydro	LTC	2023
	Upper Mamquam, BC	25	100	25	Hydro	LTC	2025
	Bone Creek, BC[4]	18	100	18	Hydro	LTC	2047
	Blue Trail, AB	66	100	66	Wind	Merchant	–
	Castle River, AB[6]	44	100	44	Wind	LTC/Merchant	2011
	Cowley North, AB	20	100	20	Wind	Merchant	–
	Cowley Ridge, AB	21	100	21	Wind	Merchant	–
	Macleod Flats, AB	3	100	3	Wind	Merchant	–
	McBride Lake, AB	75	50	38	Wind	LTC	2024
	Sinnott, AB	7	100	7	Wind	Merchant	–
	Soderglen, AB	71	50	35	Wind	Merchant	–
	Summerview 1, AB[7]	70	100	70	Wind	Merchant	–
	Taylor Wind, AB	3	100	3	Wind	Merchant	–
	Ardenville, AB[4]	69	100	69	Wind	Merchant	–
	Summerview 2, AB[4]	66	100	66	Wind	Merchant	–
	Grand Prairie, AB	25	100	25	Biomass	LTC	2019–2024
	Total Western Canada	**7,051**		**5,666**			
Eastern Canada 15 Facilities	Mississauga, ON	108	50	54	Gas	LTC	2017
	Ottawa, ON	68	50	34	Gas	LTC	2012
	Sarnia[8], ON	506	100	506	Gas	LTC	2022–2025
	Windsor, ON	68	50	34	Gas	LTC/Merchant	2016
	Moose Rapids, ON	1	100	1	Hydro	LTC	2011
	Ragged Chute, ON	7	100	7	Hydro	LTC	2011
	Misema, ON	3	100	3	Hydro	LTC	2027
	Appleton, ON	1	100	1	Hydro	LTC	2011
	Galetta, ON	2	100	2	Hydro	LTC	2011
	Kent Hills, NB	96	83	80	Wind	LTC	2033
	Kent Hills 2, NB[4]	54	100	54	Wind	LTC	2035
	Le Nordais, QC	99	100	99	Wind	LTC	2033
	Melancthon I, ON	68	100	68	Wind	LTC	2026
	Melancthon II, ON	132	100	132	Wind	LTC	2028
	Wolfe Island, ON	198	100	198	Wind	LTC	2029
	Total Eastern Canada	**1,411**		**1,273**			
United States 17 Facilities	Centralia, WA[9]	1,376	100	1,376	Coal	Merchant	–
	Centralia Gas, WA	248	100	248	Gas	Merchant	–
	Power Resources, TX	212	50	106	Gas	Merchant	–
	Saranac, NY	240	37.5	90	Gas	Merchant	–
	Yuma, AZ	50	50	25	Gas	LTC	2024
	Imperial Valley[10], CA	327	50	164	Geothermal	LTC	2016–2029
	Skookumchuk, WA	1	100	1	Hydro	–	–
	Wailuku, HI	10	50	5	Hydro	LTC	2023
	Total U.S.	**2,464**		**2,015**			
Australia 5 Facilities	Parkeston, WA	110	50	55	Gas	LTC	2016
	Southern Cross[11], WA	245	100	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			
Total		**11,281**		**9,254**			

1 Megawatts are rounded to the nearest whole number
2 Merchant capacity refers to uprates on unit 4 (53 MW), unit 5 (53 MW) and unit 6 (44 MW)
3 Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011 and 2012, respectively
4 These facilities are currently under development
5 To be retired in 2010
6 Includes 7 individual turbines at other locations
7 Comprised of 2 facilities
8 Sarnia's NMC has been adjusted from 575 MW due to decommissioning of equipment at the facility
9 Centralia Thermal's NMC has been reduced from 1,404 MW to reflect a lower plant output as a result of its conversion to burning Power River Basin coal
10 Comprised of 10 facilities
11 Comprised of 4 facilities



This management's discussion and analysis ("MD&A") should be read in conjunction with the audited 2009 consolidated financial statements. The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 23, 2010. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including its Annual Information Form, is available on SEDAR at www.sedar.com and on our website at www.transalta.com.

BUSINESS ENVIRONMENT

Overview of the Business

We are a wholesale power generator and marketer with operations in Canada, the United States ("U.S."), and Australia. In 2009, we celebrated our 100th year since incorporation. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and utilize a broad range of generation fuels including coal, natural gas, hydro, wind, geothermal, and biomass. During 2009, we increased our renewables portfolio from 15 per cent to 22 per cent of our net generating capacity with the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro") and the completion of our Blue Trail wind facility.

We operate in a variety of markets 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. The key characteristics of these markets are described below.

Demand

Demand for electricity is a fundamental driver of prices in all of our markets. Economic growth is the main driver of longer-term changes in the demand for electricity. Historically, demand for electricity in all three of our major markets has grown at an average rate of one to three per cent per year; however, the weak economic environment experienced in 2009 resulted in zero to negative demand growth in our key markets. In Alberta, demand growth is expected to resume again in 2010 after three years of stagnation. Cost reductions combined with relatively well-supported oil prices are expected to result in a modest but sustained increase in oil sands development which will, in turn, lead to higher electricity demand. Due to the economic recession, the Pacific Northwest has seen demand destruction in 2009. Load in this region is not expected to return to 2008 levels until 2011 or 2012. The long-term growth rate in this region is expected to be lower than historical trends because there is a large emphasis on energy efficiency across the region. Demand in Ontario is expected to increase in 2010 as the economy recovers. In the longer-term, demand in Ontario is expected to remain constrained as the province's economy continues to move away from manufacturing and as other energy efficiency policies take hold.

Supply

In all markets in which we operate, the cost of building most types of new generating capacity has decreased due to the global economic slowdown. Going forward, costs are expected to increase again as an economic recovery takes hold and markets tighten.

Greenhouse gas ("GHG") legislation of some form is still expected in Canada and the U.S. Given this anticipated future legislation, new generating capacity in the short- to medium-term is expected to be primarily in renewable energy and natural gas-fired generation.

Reserve margins, which measure available capacity in a market over and above the capacity needed to meet normal peak demand levels, have increased due to low or negative levels of load growth combined with new supply coming on line. It is expected that reserve margins will begin to decline slowly from current levels as load growth resumes.

Green technologies have gained favour with regulators and the general public, creating increasing pressure to supply power using renewable resources such as wind, hydro, geothermal, and solar. The economic feasibility of solar power is still being debated.

While there are many new developments that will likely impact the future supply of electricity, the low cost of our base load operations still means that our plants are supported in the market.

Transmission

Transmission refers to the bulk delivery system of power and energy between a generating unit and the distribution system that links to wholesale and/or retail customers. Transmission lines themselves serve as the physical path, transporting electricity from the generating unit to the individual distribution systems. Transmission systems are designed with sufficient reserve capacity to allow for "real time" fluctuations in both supply and demand caused by generation plants or loads coming on and off the transmission network.

Transmission capacity refers to the ability of the transmission line, or lines, to transport this bulk supply of electricity in an amount that balances the demand needs with the generating supply, allows for an amount of power required for system integrity and security, and allows for reserve capacity to respond to contingency situations on the system. Most transmission businesses in North America are still regulated.

In many markets, including Alberta, investment in transmission capacity has not kept pace with the growth in demand for electricity. Lead times in new transmission infrastructure projects are significant, are subject to extensive consultation processes with landowners, and are subject to regulatory requirements that change frequently. As a result, additions of generating capacity may not have ready access to markets until key transmission upgrades and additions are completed.

In 2009, the provincial government declared several important projects as being critical, including transmission lines between the Edmonton and Calgary regions, and between Edmonton and northeast Alberta. As a result, transmission lines within one of our key markets will receive the necessary upgrade to become less congested, and therefore will be more efficient in meeting the needs of the growth in the demand for electricity in the long-term.

Historically, transmission systems have been designed to serve loads in only their local area, and interties between jurisdictions were only a small fraction of the local generation capacity or load. Future transmission lines will need to connect beyond provincial and state borders as there is a desire to improve efficiency by distributing large quantities of electricity from one region to another.

Environmental Legislation and Technologies

Environmental issues and related legislation have, and will continue to have, an impact upon our business. Since 2007, we have incurred costs as a result of GHG legislation in Alberta. Legislation in other jurisdictions and at different levels of government is in various stages of maturity and sophistication. Our exposure to increased costs as a result of environmental legislation in Alberta is minimized through change-in-law provisions in our Power Purchase Arrangements ("PPAs").

Both the Canadian and U.S. federal governments are considering cap and trade policies to manage GHG emissions. However, economic uncertainty fueled by financial market volatility, a developing recovery, and Canada's political environment may delay the adoption of such systems. For these reasons, the Canadian government may not implement new environmental legislation until the end of 2010 or later.

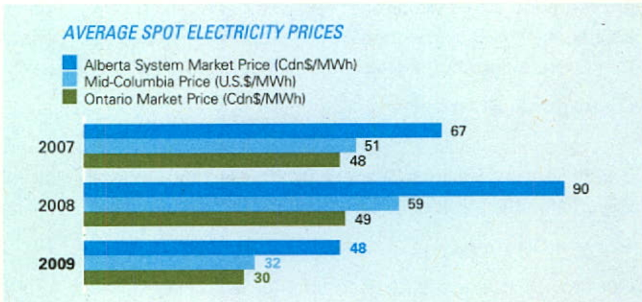
While carbon capture and storage ("CCS") technologies are being developed, these technologies are not sufficiently advanced at this time. A $2 billion dollar provincial fund and a $1 billion federal fund have been dispersed to several, large demonstration projects. Those investments are expected to bring the cost of CCS down over the next 10 years. The outlook for these costs sets a floor price for carbon abatement technologies if regulatory or trading schemes are implemented. The future of carbon regulation remains uncertain.

Economic Environment

Although we are seeing signs of an economic recovery, it is too early to judge the pace and magnitude with which the recovery will occur. Our strong financial position, available committed lines of credit, and relatively low debt maturity profile allows us to be selective about when we go to the market for financing. In 2009, we took advantage of our strong financial position by completing the acquisition of Canadian Hydro, which included issuing debt and equity to finance the purchase. The market reacted favourably to these transactions and we see continued capital market support for other projects that meet our return requirements and risk profile.

Electricity Prices

Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability as well as any contracting strategy. Our Alberta plants, operating under PPAs, pay penalties or receive payments based upon a rolling 30-day average of spot prices. Long-term contracts at Sarnia, and our short-term contracts at Centralia Thermal, minimize the impact of spot price changes.



Spot electricity prices in our markets are driven by customer demand, generator supply, natural gas prices, and the other business environment dynamics discussed above. We monitor these trends in prices and schedule maintenance, where possible, during times of lower prices.

In 2009, average spot prices decreased in Alberta, the Pacific Northwest, and in Ontario due to lower natural gas prices and weaker demand for electricity. In Alberta, prices also decreased due to increased availability across the province's thermal coal fleet.

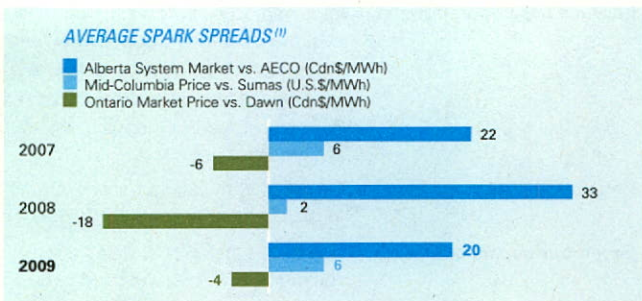
During the year, our consolidated power portfolio was over 95 per cent hedged at an average price ranging from $60–$65 per megawatt hour ("MWh") in Alberta, and an average price ranging from U.S.$50–$55/MWh in the Pacific Northwest. The use of these hedges reduced the impact of lower prices upon our consolidated financial results.

Technological advancements have made it possible to develop shale gas reserves that were previously inaccessible. In the short-term, economic conditions and new shale gas supply have created a market where supply is expected to exceed demand. This over-supply of natural gas puts negative pressure on electricity prices. In the long-term, natural gas prices will depend on investment in additional infrastructure, the shale gas supply, and the demand for natural gas in the transportation and electricity sectors.

Spark Spreads

Spark spreads measure the potential profit from generating electricity at current market rates.

A spark spread is calculated as the difference between the market price of electricity and its cost of production. The cost of production is comprised of the total cost of fuel and the efficiency, or heat rate, with which the plant converts the fuel source to electricity. For most markets, a standardized plant heat rate is assumed to be 7,000 British Thermal Units ("Btu") per Kilowatt hour ("KWh").



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

Spark spreads will also vary between different plants due to their design, the region of the world in which they operate, and the requirements of the customer and/or market the plant serves. The change in the prices of electricity and natural gas, and the resulting spark spreads in our three major markets, affect our Generation and Commercial Operations & Development ("COD") business segments.

In 2009, average spark spreads decreased in Alberta due to power prices decreasing more than natural gas prices as a result of increased availability in the province's thermal coal fleet. Spark spreads in the Pacific Northwest and Ontario increased as power prices have decreased less than natural gas prices. In the Pacific Northwest, the increase in spark spreads is primarily because 2009 had lower hydro based electricity production than 2008.

STRATEGY

Our goals are to deliver shareholder value by providing dividend yield plus disciplined comparable earnings per share[1] ("EPS") and cash flow from operations growth, while maintaining a low-to-moderate risk profile, disciplined capital allocation, and financial strength. Our comparable EPS and cash flow from operations growth is driven by growing our renewable portfolio across Canada and by further expanding our overall portfolio and operations in the western regions of Canada and the U.S. We are focusing on these geographic areas as our expertise, scale, and access to numerous fuel resources, including coal, wind, geothermal, hydro, and natural gas, allow us to create expansion opportunities in our core markets. Our strategy to achieve these goals has the following key elements:

Financial Strategy

Our financial strategy is to maintain a strong balance sheet and investment grade credit ratings to provide a solid foundation for our long-cycle, capital-intensive, and commodity-sensitive business. A strong balance sheet and investment grade credit ratings improve our competitiveness by providing greater access to capital markets, lowering our cost of capital compared to that of non-investment grade companies, and enabling us to contract our assets with customers on more favourable commercial terms. We value financial flexibility, which allows us to selectively access the capital markets when conditions are favourable.

Contracting Cash Flows

In 2009, demand and prices in our key markets decreased significantly compared to prior years primarily due to the weak economic environment. While we are not immune to softening power prices, the impact of these lower prices is significantly mitigated because approximately 89 per cent of 2010 and approximately 83 per cent of 2011 expected capacity across our fleet is contracted. It is this low-to-moderate risk contracting strategy that helps protect our cash flow and our strong financial position through economic cycles.

Operational Strategy

We manage our facilities to achieve operations that are low cost and predictable. Our target for 2010 is to increase productivity and return overall fleet availability to 90 per cent. This increase in availability involves developing and executing unit-specific maintenance plans that will create stability in our operations and reduce overall maintenance costs.

Growth Strategy

Our growth strategy is focused upon greening our portfolio to reduce our carbon footprint and develop long-term, sustainable power generation. We've delivered on this plan in 2009 by acquiring Canadian Hydro, expanding our wind portfolio, and completing efficiency uprates on Alberta Thermal units. We continue to develop opportunities for future sustainable power projects.

CAPABILITY TO DELIVER RESULTS

We have numerous core competencies and non-capital resources that give us the capability to achieve our corporate objectives, which are discussed below. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of the capital resources available that will assist in enabling us to achieve our objectives.

Operational Excellence

We seek to optimize our generating portfolio by owning and managing a mix of relatively low risk assets and fuels to deliver an acceptable and predictable return. The following chart demonstrates the significant progress that we have already made in each of our strategic focus areas.

Execution of our Strategy in 2009

Improve base operations	▪ Improved our cash flows through PPAs and other long-term contracts, which includes a new contract with the Ontario Power Authority for our Sarnia power plant that extends to 2025 ▪ Completed Unit 1 boiler modifications at Centralia Thermal ▪ Implemented productivity and cost reductions ▪ Revised our Alberta Thermal plants major maintenance schedule on a unit-by-unit basis to improve stability and predictability
Reposition coal	▪ Partnered with Alstom Canada, Capital Power Corporation, and the federal and provincial governments to fund Project Pioneer, our CCS pilot project
Green our portfolio	▪ Completed the 66 MW Blue Trail wind farm and have an additional 189 MW of wind energy under construction that is scheduled to be operational between Q1 2010 and Q1 2011 ▪ Accelerated the growth of our renewables portfolio with the acquisition of Canadian Hydro ▪ Approved the expansion of Kent Hills and the construction of Bone Creek ▪ Continued our work on the construction of our Ardenville and Summerview 2 wind farms ▪ Continued active involvement in environmental policy discussions with various levels of government in Canada and the U.S.

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

Over the last three years, our average availability has been 86.0 per cent, which is below our corporate target of 90 per cent. This decrease in average availability has been primarily due to the accelerated planned maintenance undertaken in 2009, higher than normal unplanned outages at our coal-fired plants in 2009 and 2008, and derating at Centralia Thermal in 2007. In 2009, we reviewed each unit and developed asset-specific maintenance plans to achieve our target of 90 per cent availability, which should result in more predictable performance and stable costs.

Financial Strength

We carefully manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline proved invaluable during the economic environment of 2009 and will continue to be important during 2010. We continue to maintain $2.1 billion in committed credit facilities, and as of Dec. 31, 2009, $0.7 billion was available to us. These strong ratios, available credit, continued reliable cash flow from operations, and limited debt maturity profile provide us with ample financial flexibility, and as a result we can be selective about if and when we go to the capital markets for funding.

The funding required for our growth strategy is supported by our financial strength. In 2009, we took advantage of our strong financial position by completing the acquisition of Canadian Hydro, which included issuing debt and equity to finance the purchase. The market reacted favourably to these transactions and we have maintained our investment grade credit ratings. Looking forward, we see continued capital market support for projects that meet our return requirements and risk profile.

Disciplined Capital Allocation

We are committed to optimizing the balance between returning capital to shareholders, liquidity requirements, base business investment, and growth opportunities. We have a proven track record of maintaining our long-term financial stability, which includes balancing the cash distributions to our shareholders through dividends and share buybacks, with making investments in growth projects that will deliver long-term cash flow.

We continue to grow our diversified generating fleet in order to increase production and meet future demand requirements, with all growth projects having the ability to exceed our target rates of returns. We currently have 478 megawatts ("MW") of capacity under construction, which is comprised of 225 MW of coal-fired generation, 46 MW of uprates to our thermal coal fleet, 189 MW of wind power, and 18 MW of hydro. We also have more than 600 MW of advanced development wind, hydro, and geothermal projects in our development pipeline.

In addition to our greenfield growth plans, we continue our uprates of existing facilities. These uprates add capability to our existing fleet and provide opportunities for attractive rates of return. In 2009, we completed the uprate on Unit 5 of our Sundance facility and in 2010, we will continue our work on the uprates of Units 1 and 2 of our Keephills facility.

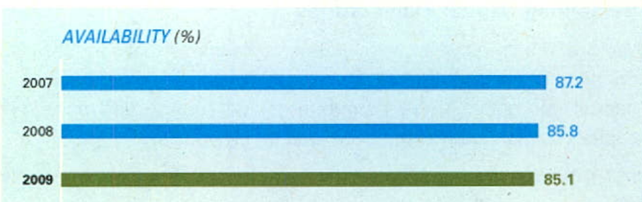
People

Our experienced leadership team is comprised of senior business leaders who bring a broad mix of skills in the electricity sector, finance, law, government, regulation, and corporate governance. The leadership team's experience and expertise, our employees' knowledge and dedication to superior operations, and our entire organization's knowledge of the renewable energy business has resulted in a long-term proven track record of financial stability and increasing shareholder value.

PERFORMANCE METRICS

We have key measures that, in our opinion, are critical to evaluating how we are progressing towards meeting our goals. These measures, which include a mix of operational, risk management, and financial metrics, are discussed below.

Availability



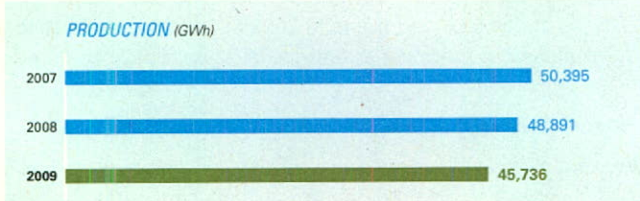
Our plants must be available at all times throughout the year to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, and reduced production as a result of derates. Our goal is to minimize these events through regular assessments of our equipment and a comprehensive review of our maintenance plans. Over the past three years we have achieved an average availability of 86.0 per cent, which is below our long-term target of 90 per cent. Our availability in 2009 was 85.1 per cent.

Availability for the year ended Dec. 31, 2009 decreased due to higher planned and unplanned outages at Alberta Thermal, higher unplanned outages at Centralia Thermal, and higher planned outages at the Windsor and Mississauga plants, partially offset by lower planned outages at Centralia Thermal and lower planned and unplanned outages at Genesee 3.

Availability for the year ended Dec. 31, 2008 decreased due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher planned outages as a result of equipment modifications at Centralia Thermal, partially offset by lower derates at Centralia Thermal as in 2007 we conducted test burns of powder river basin ("PRB") coal.

Production

Production is a significant driver of revenue in some of our contracts and in our ability to capture market opportunities. Our goal is to optimize production through planned maintenance programs and the use of monitoring programs to minimize unplanned outages and derates. We combine these programs with our monitoring of market prices to optimize our results under both our contracted and merchant facilities.

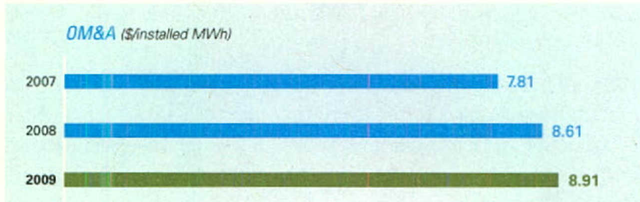


Production for the year ended Dec. 31, 2009 decreased 3,155 gigawatt hours ("GWh") due to higher economic dispatching and higher unplanned outages at Centralia Thermal, higher planned and unplanned outages at Alberta Thermal, lower PPA customer demand at Alberta Thermal and Sheerness, the expiration of the long-term contract at Saranac, and lower hydro volumes, partially offset by higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, lower planned outages at Centralia Thermal, and lower planned and unplanned outages at Genesee 3.

For the year ended Dec. 31, 2008, production decreased 1,504 GWh due to higher unplanned outages at Alberta Thermal and Genesee 3, higher planned outages at Centralia Thermal, lower market heat rates at Sarnia, and economic dispatching at Centralia Thermal, partially offset by lower unplanned outages at Centralia Thermal, higher merchant volumes due to the uprate on Unit 4 at our Sundance facility, and lower derates at Centralia Thermal resulting from test burns of PRB coal in 2007.

Productivity

Our operations, maintenance, and administration ("OM&A") costs reflect the operating cost of our facilities. These costs can fluctuate due to the timing and nature of planned maintenance activities. The remainder of OM&A costs reflects the cost of day-to-day operations. Our target is to offset the impact of inflation in our recurring operating costs as much as possible through cost control and targeted productivity initiatives. We measure our ability to maintain productivity on OM&A based on the cost per installed MWh of capacity.



For the year ended Dec. 31, 2009, OM&A costs per MWh hour increased primarily due to higher planned outages and unfavourable foreign exchange rates, partially offset by targeted cost savings throughout the Corporation, and lower compensation costs.

For the year ended Dec. 31, 2008, OM&A costs per MWh increased due to cost escalations, higher planned maintenance costs, and increased compensation costs.

Safety

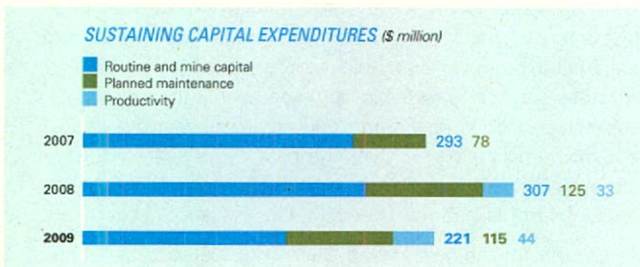
Safety is a top priority with all of our staff, contractors, and visitors. Our goal is to improve safety by reducing our Injury Frequency Rate ("IFR") to 1 over the next five years.

	2007	2008	2009	Target
Injury Frequency Rate	1.76	1.28	**1.41**	1 over next five years

The IFR increased in 2009 as a result of us not meeting safety targets while completing the uprate on Unit 5 of our Sundance facility. In 2008, the IFR decreased as a direct result of our continuous efforts to improve safety.

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that requires consistent and stable capital expenditures. Our sustaining capital comprises three components: (1) routine and mine capital, (2) planned maintenance, and (3) productivity.



In 2009, we spent $86 million less on routine and mine capital, $10 million less on planned maintenance, and an additional $11 million on productivity compared to 2008. The decrease in both routine and mine capital and planned maintenance in 2009 was due to lower mine capital and decreased spending on equipment modifications at Centralia Thermal. The increase in productivity expenditures was for various projects undertaken throughout the Corporation to improve operations and increase efficiencies.

In 2008, we spent an additional $14 million on routine and mine capital and an additional $47 million on planned maintenance compared to 2007. The increase in both routine and mine capital and planned maintenance was due to higher unplanned outages at Alberta Thermal and Genesee 3, equipment modifications at Centralia Thermal, and higher planned maintenance activities across the fleet. In 2007, there were no productivity expenditures.

Our annual target for sustaining capital expenditures is expected to decrease for 2010 to approximately $295 to $340 million, primarily due to lower planned maintenance. We expect to return to normal sustaining capital expenditure levels of $310 to $355 million in 2011.

Earnings and Cash Flow From Operating Activities

We focus our base business on delivering strong earnings and cash flow growth.

	2007	2008	2009	Target
Comparable earnings per share	1.31	1.46	**0.90**	Low double digit growth
EBITDA[1]	980	1,006	**895**	Low double digit growth
Cash flow from operating activities	847	1,038	**580**	850–950

1 EBITDA is not defined under Canadian GAAP. Presenting EBITDA from period to period provides management and investors with a proxy for the amount of cash generated from operating activities before net interest expense, non-controlling interests, income taxes, and working capital adjustments. Refer to the Non-GAAP Measures section of this MD&A for a further discussion of EBITDA, including a reconciliation to net earnings.

In 2009, comparable earnings per share and earnings before interest, taxes, depreciation, and amortization ("EBITDA") decreased due to higher planned and unplanned outages at Alberta Thermal, lower hydro volumes and prices, and lower trading margins.

In 2008, comparable earnings per share and EBITDA increased due to favourable pricing in our core markets, higher merchant volumes due to the uprate on Unit 4 at our Sundance facility, and strong Energy Trading results across all markets, partially offset by higher unplanned outages at Alberta Thermal.

In 2009, cash flow from operating activities decreased due to lower cash earnings, the receipt of an additional PPA payment in 2008, higher inventory balances in 2009, and unfavourable movements in other working capital balances.

In 2008, cash flow from operating activities increased due to an increase in cash earnings and favourable changes in working capital including the timing of PPA receipts in 2008.

Investment Grade Ratios

Investment grade ratings support contracting activities and provide better access to capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and cash flow coverage ratios to support stable investment grade credit ratings.

	2007	2008	2009	Target
Cash flow to interest coverage (times)	6.6	7.2	**4.9**	4–5
Cash flow to debt (%)	30.7	31.1	**20.1**	20–25
Debt to invested capital (%)	46.8	48.1	**56.1**	55–60

Cash flow to interest coverage decreased in 2009 compared to the same period in 2008 as a result of lower cash flow from operating activities and higher interest expense. Cash flow to interest coverage increased in 2008 compared to 2007 as a result of increased cash from operating activities and lower interest expense.

Cash flow to debt decreased in 2009 due to a decrease in cash flows from operating activities and higher debt as a result of our issuances of senior- and medium-term notes during 2009 to acquire Canadian Hydro. Cash flow to debt increased in 2008 due to an increase in cash flows from operating activities, which offset the increase in debt balances.

Debt to invested capital increased in 2009 compared to the same period in 2008 as a result of the issuance of debt throughout the year to fund growth and for the acquisition of Canadian Hydro. Debt to invested capital increased in 2008 compared to 2007 as a result of the issuance of senior notes in the amount of U.S.$500 million.

We seek to maintain financial flexibility by using multiple sources of capital to finance capital allocation plans effectively, while maintaining a sufficient level of available liquidity to support contracting and trading activities. Further, financial flexibility allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are beneficial to our financial results.

Shareholder Value

Our business model is designed to deliver low-to-moderate risk-adjusted sustainable returns and maintain financial strength and flexibility, which enhances shareholder value in a capital intensive, long-cycle, commodity-based business. Our target is to consistently grow our comparable return on capital employed ("ROCE")[2] and total shareholder return ("TSR")[2] each year.

The table below shows our historical performance and targets on these measures:

	2007	2008	2009	Target
Comparable ROCE (%)	9.7	9.6	**5.8**	> 10%
TSR (%)	29.0	(23.9)	**1.4**	> 10%

Comparable ROCE decreased in 2009 due to lower comparable earnings as a result of higher planned and unplanned outages at Alberta Thermal, lower hydro volumes and prices, and lower trading margins. Comparable ROCE in 2008 was consistent with 2007.

The limited increase in TSR for 2009 is due to the beginning of the slow recovery from the economic recession in 2008. The decrease in TSR for 2008 was due to a decrease in share price as a result of the economic recession, during which time the Standard & Poor's/Toronto Stock Exchange Composite Index decreased 35 per cent.

2 These measures are not defined under Canadian GAAP. We evaluate our performance and the performance of our business segments using a variety of measures. These measures are not necessarily comparable to a similarly titled measure of another company. Comparable ROCE is a measure of the efficiency and profitability of capital investments and is calculated by taking comparable earnings before net interest expense, non-controlling interests and taxes, and dividing by the average invested capital excluding AOCI. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods. TSR is the total amount returned to investors over a specific holding period and includes capital gains, capital losses, and dividends.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have two business segments: Generation and 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.

Some of our accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Critical accounting policies and estimates include: revenue recognition, valuation and useful life of property, plant, and equipment ("PP&E"), financial instruments, asset retirement obligation ("ARO"), valuation of goodwill, income taxes, and employee future benefits. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further discussion.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant items from the Consolidated Statements of Earnings and the Consolidated Balance Sheets. While individual line items on the Consolidated Balance Sheets will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items is reflected in the equity section.

HIGHLIGHTS AND SUMMARY OF RESULTS

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

Year ended Dec. 31	2009	2008	2007
Availability (%)	**85.1**	85.8	87.2
Production (GWh)	**45,736**	48,891	50,395
Revenue	**2,770**	3,110	2,775
Gross margin[1]	**1,542**	1,617	1,544
Operating income[1]	**378**	533	541
Net earnings	**181**	235	309
Net earnings per share, basic and diluted	**0.90**	1.18	1.53
Comparable earnings per share	**0.90**	1.46	1.31
Cash flow from operating activities	**580**	1,038	847
Free cash flow[1] (deficiency)	**(117)**	121	111
Cash dividends declared per share	**1.16**	1.08	1.00

As at Dec. 31	2009	2008	2007
Total assets	**9,762**	7,824	7,157
Total long-term financial liabilities	**5,512**	3,645	2,858

1 Gross margin, operating income, and free cash flow are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of these items, including reconciliations to net earnings and cash flow from operating activities.

REPORTED EARNINGS

The primary factors contributing to the change in net earnings for the years ended Dec. 31, 2009 and 2008 are presented below:

Net earnings for the year ended Dec. 31, 2007	309
Increase in Generation gross margins	7
Mark-to-market movements—Generation	16
Increase in COD gross margins	50
Increase in operations, maintenance, and administration costs	(60)
Increase in depreciation expense	(22)
Gain on sale of mining equipment in 2007	(11)
Decrease in net interest expense	23
Increase in equity loss	(47)
Increase in non-controlling interests	(13)
Increase in income tax expense	(3)
Other	(14)
Net earnings for the year ended Dec. 31, 2008	235
Decrease in Generation gross margins	(33)
Mark-to-market movements—Generation	16
Decrease in COD gross margins	(58)
Increase in operations, maintenance, and administration costs	(30)
Increase in depreciation expense	(47)
Writedown of mining development costs	(16)
Increase in net interest expense	(34)
Equity loss recorded in 2008	97
Decrease in non-controlling interests	23
Decrease in income tax expense	8
Other	20
Net earnings for the year ended Dec. 31, 2009	**181**

For the year ended Dec. 31, 2009, Generation gross margins, net of mark-to-market movements, decreased due to higher planned outages at Alberta Thermal, lower hydro volumes and prices, and the expiration of the long-term contract at Saranac, partially offset by lower planned and unplanned outages at Genesee 3, higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, favourable foreign exchange rates, and favourable contractual pricing.

In 2008, Generation gross margins, net of mark-to-market movements, increased due to favourable pricing, lower derates at Centralia Thermal, and higher merchant volumes as a result of the uprate on Unit 4 at our Sundance facility, partially offset by higher unplanned outages at Alberta Thermal and Genesee 3.

For the year ended Dec. 31, 2009, COD gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

In 2008, COD gross margins increased due to all regions experienced positive results in 2008, with the increase primarily attributable to successful trading strategies involving regional power demand and price differentials in the eastern region.

For the year ended Dec. 31, 2009, OM&A costs increased primarily due to higher planned outages and unfavourable foreign exchange rates, partially offset by targeted cost savings throughout the Corporation, and lower compensation costs. In 2008, OM&A costs increased due to cost escalations, higher planned maintenance costs, and increased compensation costs.

For the year ended Dec. 31, 2009, depreciation expense increased due to an increased asset base, unfavourable foreign exchange rates, and the retirement of certain assets that were not fully depreciated during planned maintenance activities, partially offset by lower production at Saranac and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal in 2008.

In 2008, depreciation expense increased compared to the same period in 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal.

In 2006, we ceased mining activities at the Centralia mine but continued to develop the option to mine the Westfield site, a coal reserve located adjacent to Centralia Thermal. With the successful modifications of the boilers at Centralia Thermal and longer-term contracts in place to supply coal, the project to develop the Westfields site has now been placed on hold indefinitely and the costs that have been capitalized were expensed during the fourth quarter of 2009.

Net interest expense increased for the year ended Dec. 31, 2009 due to higher long-term debt levels and lower interest income as a result of the receipt of interest income from a tax settlement in 2008, partially offset by lower interest rates and higher capitalized interest primarily due to the construction of Keephills 3. In 2008, net interest expense decreased primarily due to interest received on the settlement of a tax issue and higher capitalized interest, partially offset by lower interest income from cash deposits.

In the first quarter of 2008, an equity loss of $97 million was recorded to reflect the writedown of our Mexican equity investment that was sold in the fourth quarter of the same year. Equity loss increased for the year ended Dec. 31, 2008 compared to the same period in 2007 due to the writedown of our Mexican equity investment in the first quarter of 2008, partially offset by a tax expense recorded in 2007 as a result of changes in tax law in Mexico.

For the year ended Dec. 31, 2009, non-controlling interests decreased primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac. Non-controlling interests for the year ended Dec. 31, 2008 were comparable to 2007.

For the year ended Dec. 31, 2009, income tax expense decreased due to lower pre-tax earnings and the recovery recorded for a change in future tax rates related to tax liabilities recorded in prior periods, partially offset by the income tax recovery related to tax positions recorded in 2008. Income tax expense for the year ended Dec. 31, 2008 was comparable to the same period in 2007.

SIGNIFICANT EVENTS

Our consolidated financial results include the following significant events:

2009

Medium-Term Notes Offerings

On Nov. 18, 2009, we completed our offering in the Canadian bond market of $400 million medium-term notes maturing in 2019 and bearing an interest rate of 6.40 per cent. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

On May 29, 2009, we completed our offering in the Canadian bond market of $200 million medium-term notes maturing in 2014 and bearing an interest rate of 6.45 per cent. The net proceeds from the offering were used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

Senior Notes Offering

On Nov. 13, 2009, we completed our offering of U.S.$500 million senior notes maturing in 2015 and bearing an interest rate of 4.75 per cent. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

Sale of Common Shares

On Nov. 5, 2009, we completed our public offering of 20,522,500 Common shares at a price of $20.10 per common share, which resulted in net proceeds of approximately $413 million. The net proceeds from the offering were used to repay a portion of the indebtedness relating to our acquisition of Canadian Hydro.

Blue Trail

On Nov. 2, 2009, our Blue Trail wind farm began commercial operations on budget and one month ahead of schedule. The 66 MW facility is located southwest of Fort McLeod in southern Alberta.

Keephills 3

On Oct. 26, 2009, the Board of Directors approved an increase in the construction cost of Keephills 3 to $988 million due to a change in our original expectations of the labour required to complete the project, and a change to the commencement of commercial operations from the first quarter of 2011 to the second quarter of 2011. Even with the delay of operations and increased cost, Keephills 3 is still expected to meet our investment hurdles.

Carbon Capture and Storage

On Oct. 14, 2009, the federal and provincial governments announced that our CCS project, Project Pioneer, has received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a Front End Engineering and Design ("FEED") study to determine if the project is viable. The FEED study is expected to cost $20 million; $10 million will come from the federal government, $5 million will come from the provincial government, and $5 million will come from TransAlta and from industry partners Alstom Canada and Capital Power Corporation ("Capital Power"). The FEED study is expected to be completed by the end of 2010 or in early 2011, and if we proceed with construction, the prototype plant has a targeted start-up date of 2015.

Acquisition of Canadian Hydro

On Oct. 5, 2009, we entered into a definitive pre-acquisition agreement with Canadian Hydro to acquire all of their issued and outstanding common shares for $5.25 per share in cash. On Oct. 23, 2009, we acquired 87 per cent of Canadian Hydro through the purchase of all of their issued and outstanding shares. On Nov. 4, 2009, we acquired the remaining 13 per cent. The total cash consideration of the acquisition was $766 million. The results of Canadian Hydro are included in our consolidated financial statements from Oct. 23, 2009, when we acquired control.

Canadian Hydro operated 694 MW of wind, hydro, and biomass facilities in Alberta, Ontario, Quebec, and British Columbia. Canadian Hydro's assets are highly contracted with counterparties of recognized financial standing. On a combined basis at Dec. 31, 2009, we have 9,199 MW of gross generating capacity[1] in operation (8,775 MW net ownership interest). The combined renewables portfolio includes more than 1,900 MW in operation, or 22 per cent of the total portfolio. In addition, there was a combined 424 MW net under construction and over 600 MW in advanced-stage development at Dec. 31, 2009.

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

The following table depicts the impact of Canadian Hydro on our consolidated operations portfolio by geographic region and fuel type:

Net Capacity Ownership Interest (MW)

Dec. 31, 2009	Canadian Hydro	TransAlta[1]	TransAlta Consolidated
Western Canada	183	5,059	5,242
Eastern Canada	511	707	1,218
International	–	2,315	2,315
	694	8,081	8,775
Coal	–	4,967	4,967
Natural Gas	–	1,843	1,843
Geothermal	–	164	164
Wind	583	300	883
Hydro	86	807	893
Biomass	25	–	25
	694	8,081	8,775

1 *Excluding Canadian Hydro.*

The following table depicts the impact of certain Canadian Hydro financial assets and long-term financial liabilities on our consolidated financial results:

As at Dec. 31, 2009	Canadian Hydro	TransAlta[1]	TransAlta Consolidated
Property, plant, and equipment	1,289	6,289	7,578
Intangible assets	176	157	333
Risk management liabilities	31	47	78
Long-term debt, non-recourse	374	180	554
Future income tax liabilities	28	609	637

1 *Excluding Canadian Hydro.*

Sarnia Contract

On Sept. 30, 2009, we entered into a new agreement with the Ontario Power Authority ("OPA") for our Sarnia regional cogeneration power plant. The contract is capacity based and the term of the new agreement is from July 1, 2009 through to the end of 2025. While the specific terms and conditions of the new agreement are confidential, the OPA has indicated that the agreement is in line with other similar agreements issued by the OPA.

Major Maintenance Plans

On May 20, 2009, we announced the advancement of a major maintenance outage on Unit 3 of our Sundance facility from the second quarter of 2010 into the second and third quarters of 2009. The advancement of the maintenance outage took advantage of low power prices, optimized preventative maintenance in the short-term, and is expected to provide an economic cash benefit over the two-year period due to improved unit availability. As a result of the change in schedule, 2009 lost GWh increased by 396 GWh and net earnings declined by $24 million ($0.12 per share).

Normal Course Issuer Bid ("NCIB") Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval to purchase, for cancellation, up to 9.9 million of our common shares representing 5 per cent of our 198 million common shares issued and outstanding as at April 30, 2009. 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. No purchases were made under the NCIB in 2009.

Chief Operating Officer

On April 28, 2009 we announced the appointment of Dawn Farrell to the position of Chief Operating Officer. In this new role, Ms. Farrell leads our operations, trading, development, 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, took on a new assignment as Chief Productivity Officer for the remainder of 2009 with the responsibility for identifying strategies to create sustainable costs savings across the Corporation. Mr. Langhammer formally retired 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 69 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the capital cost of the project is the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the remainder of the Ardenville wind project is expected to commence in the first quarter of 2011.

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 facility ("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 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 $10 million, respectively representing both lost merchant revenue and penalties.

In response to this event, we gave notice of a High Impact Low Probability Force Majeure Event to the PPA Buyer and the Balancing Pool, and we paid the required penalties related to the derate. On April 27, 2009, the Balancing Pool rejected our assertion that this outage should be regarded as a High Impact Low Probability Force Majeure Event. As a result, we also record an additional charge in the second quarter of $7 million after-tax related to this event. We settled the issue in the third quarter and the terms of the settlement are confidential.

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 of Unit 1 expected by the end of 2011 and Unit 2 by the end of 2012.

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.

2008

Kent Hills Wind Farm

On Dec. 31, 2008, our 96 MW Kent Hills Wind Farm, which is located 30 kilometres southwest of Moncton, New Brunswick, began commercial operations. We constructed, own, and operate the Kent Hills facility. Total capital costs for the construction of Kent Hills were approximately $170 million. Natural Forces Technologies Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills project subsequent to the commencement of commercial operations.

Debentures

On July 31, 2008, $100 million of debentures issued by TransAlta Utilities Corporation ("TAU") were redeemed at the option of the holder of the debentures at a price of $98.45 per $100 of notional amount. The debentures had been issued at a fixed interest rate of 5.49 per cent, maturing in 2023, and were redeemable at the option of the holder in 2008.

On Oct. 10, 2008, $50 million of debentures issued by TAU were redeemed at a negotiated price. The debentures were originally issued at a fixed interest rate of 5.66 per cent and were to mature in 2033.

As of Dec. 12, 2008, TAU was no longer a reporting issuer.

On Jan. 1, 2009, TAU transferred certain generation and transmission assets to a newly formed wholly owned partnership, TransAlta Generation Partnership ("TAGP"), before amalgamating with TransAlta Corporation.

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

On July 18, 2008, being unable to reach an agreement with the IBEW representing our Alberta Thermal and Hydro employees, the Government of Alberta approved our application to have the matter referred to a Disputes Inquiry Board. As part of this process, the ability of the IBEW to strike or for us to exercise a lockout was suspended. Contract negotiations continued during this process with the assistance of a government-appointed mediator.

On Sept. 19, 2008, the Disputes Inquiry Board concluded that union members at three of our facilities were required to vote in accordance with the original terms of the Memorandum of Settlement. Discussions were held with the Labour Relations Board and the IBEW to determine a voting process and on Oct. 17, 2008, the IBEW membership at our Alberta Thermal and Hydro facilities reached a settlement and voted to accept our revised offer and ratify the Memorandum of Settlement.

Genesee 3

On Oct. 10, 2008, the Genesee 3 plant, a 450 MW joint venture with Capital Power (225 MW net ownership interest), experienced an unplanned outage as a result of a turbine blade failure. Capital Power, the plant operator, returned the unit to service on Nov. 18, 2008. As a result of the event, fourth quarter total production was reduced by 210 GWh and gross margin decreased by $15 million.

Mexican Equity Investment

On Oct. 8, 2008, we successfully completed the sale of our Mexican equity investment to InterGen Global Ventures B.V. ("InterGen") for gross proceeds of $334 million (U.S.$304 million). The sale included the plants and all associated commercial arrangements. The actual after-tax loss as a result of the sale was $62 million. The pre-tax charge of $97 million was recorded in equity loss.

LS Power and Global Infrastructure

On July 18, 2008, we received a non-binding letter from LS Power Equity Partners, an entity associated with Luminus Management LLC, and Global Infrastructure Partners regarding engaging in a dialogue about a possible acquisition of TransAlta.

On Aug. 6, 2008, the Board of Directors unanimously concluded that the proposal undervalued the Corporation and was not in the best interest of TransAlta and its shareholders. The Board made its determination following a detailed and comprehensive review by a special committee of independent directors and based on advice from financial and legal advisors.

On Oct. 7, 2008, LS Power Equity Partners and Global Infrastructure Partners announced that their proposal set out in the letter on July 18, 2008 had been withdrawn.

Potential Breach of Keephills Ash Lagoon

On July 26, 2008, we detected a crack in the dyke wall at our Keephills ash lagoon. We immediately notified Alberta Environment and the local authorities, and began taking measures to control and mitigate the effects of any potential breach and release of water from the lagoon. A series of dykes were constructed at the Keephills ash lagoon site and the risk associated with the potential breach was successfully mitigated.

Expansion at Summerview

On May 27, 2008, we announced a 66 MW expansion at our Summerview wind farm located in southern Alberta near Pincher Creek. The total capital cost of the project was $123 million and commercial operations commenced on Feb. 23, 2010. Please refer to the Subsequent Events section of this MD&A.

Senior Notes Offering

On May 9, 2008, we completed an offering of U.S.$500 million of 6.65 per cent senior notes due in 2018. The net proceeds from the offering were used for debt repayment, financing of our long-term investment plan, and for general corporate purposes.

Normal Course Issuer Bid 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.

For the year ended Dec. 31, 2008, we purchased 3,886,400 shares (2007 – 2,371,800 shares) at an average price of $33.46 per share (2007 – $31.59 per share). Purchases were made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. The shares were purchased for an amount higher than their weighted average book value of $8.95 per share (2007 – $8.92 per share) resulting in a reduction of retained earnings of $95 million (2007 – $54 million).

Uprate at Sundance Facility

On April 21, 2008, we announced a 53 MW efficiency uprate at Unit 5 of our Sundance facility. The total capital cost of the project was approximately $77 million. Commercial operations commenced in the fourth quarter of 2009.

Greenhouse Gas Emissions

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

Dividend Policy and Dividend Increase

On Feb. 1, 2008, the Board of Directors declared a quarterly dividend of $0.27 per share on common shares. This represented an increase of $0.02 per share to the quarterly dividend which on an annual basis yielded $1.08 per share versus $1.00.

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

Blue Trail Wind Power Project

On Feb. 13, 2008, we announced plans to design, build, and operate Blue Trail, a 66 MW wind power project in southern Alberta. The capital cost of the project was $113 million. Commercial operations commenced in the fourth quarter of 2009.

2007

Tax Rate Change

On Dec. 14, 2007, Bill C-28 received Royal Assent, lowering the federal corporate income tax rate to 15 per cent by 2012. These are further rate reductions from the ones included in Bill C-52, which received Royal Assent on June 22, 2007. A total of $48 million of future income tax benefit was recorded in 2007.

TransAlta Power, L.P.

On Dec. 6, 2007, Stanley Power, an indirect wholly owned subsidiary of Cheung Kong Infrastructure Holdings Limited, announced that it had paid for and acquired all of the limited partnership units of TransAlta Power, L.P. at the price of $8.38 in cash per unit. The transaction was valued at approximately $629 million. This transaction had no material impact on us.

Ottawa Power Purchase Agreement

On Oct. 12, 2007, we signed an agreement amending our original long-term contract with the Ontario Electricity Financial Corporation ("OEFC") for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant operations following the expiry of long-term natural gas supply contracts. The agreement will be in effect from Nov. 1, 2007 until Dec. 31, 2012.

Mexico Tax Reform

On Oct. 1, 2007, the Mexican government enacted law replacing the existing asset tax with a new flat tax starting Jan. 1, 2008. The flat tax is a minimum tax whereby the greater of income tax or flat tax is paid. In computing the flat tax, only 50 per cent of the undepreciated tax balance of certain capital assets acquired before Sept. 1, 2007 is deductible over 10 years. In addition, no deduction or credit is permitted in respect of interest expense, and net operating losses for income taxes as at Dec. 31, 2007 cannot be carried forward to shelter flat tax. We recorded a $28 million charge in equity losses as a result of this change.

NCIB Program

On Sept. 11, 2007, we announced an expansion of our NCIB program under which we could purchase, for cancellation, up to 20.2 million of our common shares or approximately 10 per cent of the 202.0 million common shares issued and outstanding as at April 23, 2007. The 2007 NCIB program started on May 3, 2007 and continued until May 2, 2008.

For the year ended Dec. 31, 2007, we purchased 2,371,800 shares at an average price of $31.59 per share. Purchases were made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. This purchase price was in excess of the weighted average book value of $8.92 per share, resulting in a reduction to retained earnings of $54 million.

New Brunswick Power Purchase Agreement

On Jan. 19, 2007, we announced a 25-year contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 96 MW of wind power in New Brunswick ("Kent Hills").

Sundance Unit 4 Uprate

In December 2007, we completed an uprate on Unit 4 of our Sundance facility that added 53 MW of capacity to this facility.

Greenhouse Gas Emissions Standards

Effective July 1, 2007, the *Climate Change and Emissions Management Amendment Act* was enacted into law in Alberta. Under the legislation, baselines and targets for GHG emissions intensity are set on a facility by facility basis. The legislation requires a 12 per cent reduction in carbon emission intensity over a baseline for the period 2003 to 2005, established as at Dec. 31, 2007. New facilities or those in operation for less than three years are exempt; however, upon the fourth year of operations, the facility baseline is established and gradually reduces by year of operation until the eighth year, by which emissions must be 12 per cent below the established baseline. Emissions over the baseline are subject to a charge that must be paid annually. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover most compliance costs from our PPA customers. After flow-through, the net compliance costs were estimated to be approximately $5 million per year until we are able to meet the targets for GHG emissions under the Act.

Dragline Deposit

On June 21, 2007, TAU entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal for the Keephills 3 joint venture project. The total dragline purchase costs are approximately $150 million, with final payments for goods and services due by July 2010. The total payments made under this agreement in 2007 were $18 million.

Keephills 3 Power Plant

On Feb. 26, 2007, we announced that we would be building the 450 MW Keephills 3 coal-fired power plant. The plant is being developed jointly by Capital Power and by us. The capital cost of the project is expected to be approximately $1.9 billion, including associated mine capital, and is anticipated to begin commercial operations in the second quarter of 2011. We own a 50 per cent interest in this unit.

SUBSEQUENT EVENTS

Summerview 2

On Feb. 23, 2010, our 66 MW Summerview 2 wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was $123 million.

Kent Hills Expansion

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

DISCUSSION OF SEGMENTED RESULTS

GENERATION: **Owns and operates hydro, wind, geothermal, biomass, 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. At Dec. 31, 2009, Generation had 9,199 MW of gross generating capacity in operation (8,775 MW net ownership interest) and 424 MW net under construction. At Dec. 31, 2009, 1,964 MW net was renewable. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of this MD&A.**

During 2009, we completed the acquisition of Canadian Hydro, which operates 694 MW of wind, hydro, and biomass facilities in Alberta, Ontario, Quebec, and British Columbia. We also completed the uprate on Unit 5 of our Sundance facility and the construction of the Blue Trail wind farm in southern Alberta. Please refer to the Significant Events section of this MD&A for further details.

We have strategic alliances with Stanley Power, Capital Power, ENMAX Corporation ("ENMAX"), MidAmerican Energy Holdings Company ("MidAmerican"), Nexen Incorporated ("Nexen"), and Brookfield Asset Management Inc. ("Brookfield"). Stanley Power owns the minority interest in TransAlta Cogeneration, L.P. ("TA Cogen"). The Capital Power alliance provided the opportunity for us to acquire 50 per cent ownerships in both the 450 MW Genesee 3 project and the Taylor Hydro facility, as well as to build the Keephills 3 project. ENMAX and our Corporation each own 50 per cent of the partnership in the McBride Lake wind project. MidAmerican owns the other 50 per cent interest in CE Generation, LLC ("CE Gen") and Wailuku Holding Company, LLC. Nexen and our Corporation each have a 50 per cent ownership in the Soderglen wind project. Brookfield owns the other 50 per cent interest in our Pingston hydro facility.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Canadian and U.S. markets.

The results of the Generation segment are as follows:

Year ended Dec. 31	2009		2008		2007	
	Total	Per installed MWh	Total	Per installed MWh	Total	Per installed MWh
Revenues	**2,723**	**36.37**	3,005	40.63	2,720	37.03
Fuel and purchased power	**(1,228)**	**(16.40)**	(1,493)	(20.18)	(1,231)	(16.76)
Gross margin	**1,495**	**19.97**	1,512	20.45	1,489	20.27
Operations, maintenance, and administration	**550**	**7.35**	487	6.58	447	6.08
Depreciation and amortization	**453**	**6.05**	409	5.53	391	5.33
Taxes, other than income taxes	**22**	**0.29**	19	0.26	20	0.27
Intersegment cost allocation	**32**	**0.43**	30	0.41	27	0.37
Operating expenses	**1,057**	**14.12**	945	12.78	885	12.05
Operating income	**438**	**5.85**	567	7.67	604	8.22
Installed capacity (GWh)	**74,866**		73,969		73,447	
Production (GWh)	**45,736**		48,891		50,395	
Availability (%)	**85.1**		85.8		87.2	

Generation Production and Gross Margins

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

Year ended Dec. 31, 2009	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Western Canada	**30,443**	**46,334**	**1,182**	**435**	**747**	**25.51**	**9.39**	**16.12**
Eastern Canada	**3,829**	**8,256**	**428**	**225**	**203**	**51.84**	**27.25**	**24.59**
International	**11,464**	**20,276**	**1,113**	**568**	**545**	**54.89**	**28.01**	**26.88**
	45,736	**74,866**	**2,723**	**1,228**	**1,495**	**36.37**	**16.40**	**19.97**

Year ended Dec. 31, 2008	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Western Canada	32,364	46,096	1,314	525	789	28.51	11.39	17.12
Eastern Canada	3,290	7,194	501	351	150	69.64	48.79	20.85
International	13,237	20,679	1,190	617	573	57.55	29.84	27.71
	48,891	73,969	3,005	1,493	1,512	40.63	20.18	20.45

Year ended Dec. 31, 2007	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Western Canada	33,398	45,385	1,302	449	853	28.69	9.90	18.79
Eastern Canada	3,775	7,173	443	303	140	61.75	42.19	19.56
International	13,222	20,889	975	479	496	46.66	22.92	23.74
	50,395	73,447	2,720	1,231	1,489	37.03	16.76	20.27

Western Canada

Our Western Canada assets consist of five coal facilities, three natural gas-fired facilities, 20 hydro facilities, 10 wind farms, and one biomass facility with a total gross generating capacity of 5,528 MW (5,242 MW net ownership interest). On Feb. 23, 2010, commercial operations of our 66 MW Summerview 2 wind farm commenced. Refer to the Subsequent Events section of this MD&A for further details. We are currently constructing a 450 MW (225 MW net ownership interest) merchant thermal plant at our Keephills facility under a joint venture with Capital Power, which is scheduled to enter commercial production in 2011. We are currently performing uprates of 23 MW each on Unit 1 and Unit 2 of our Keephills facility, which are scheduled to be completed by the fourth quarter of 2011 and 2012, respectively. We are also currently constructing Ardenville, a wind farm in southern Alberta, and Bone Creek, a hydro facility in British Columbia. Ardenville will have a generating capacity of 69 MW and is scheduled to enter commercial production in 2011. Bone Creek will have a generating capacity of 18 MW and is scheduled to enter commercial production in 2011.

Our Sundance, Keephills, and Sheerness plants, and 13 hydro facilities operate under PPAs with a gross generating capacity of 4,083 MW (3,888 MW net ownership interest). Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability, and an excess energy payment for power production above committed capacity. Additional capacity added to these units that is not included in capacity covered by the PPAs is sold on the merchant market.

Our Wabamun, Genesee 3, a portion of our Poplar Creek and Castle River facilities, four hydro facilities, and nine additional wind facilities sell their production on the merchant spot market. In order to manage our exposure to changes in spot electricity prices as well as capture value, we contract a portion of this production to guarantee cash flows.

Due to their close physical proximity, three of our coal-fired plants, Sundance, Keephills, and Wabamun, are operated and managed collectively and are referred to as "Alberta Thermal." Our Wabamun plant will be decommissioned in the first quarter of 2010.

McBride Lake, Meridian, Fort Saskatchewan, a significant portion of our Poplar Creek and Castle River assets, and three hydro facilities earn revenues under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam as well as for ancillary services. These contracts are for an original term of at least 10 years and payments do not fluctuate significantly with changes in levels of production.

Our Grande Prairie biomass facility earns revenues under long-term contracts based on actual production delivered at a specified price per MWh.

For the year ended Dec. 31, 2009, production decreased 1,921 GWh due to higher planned and unplanned outages at Alberta Thermal, lower PPA customer demand at Alberta Thermal and Sheerness, and lower hydro volumes, partially offset by lower planned and unplanned outages at Genesee 3, and higher wind volumes due to the acquisition of Canadian Hydro.

In 2008, production decreased 1,034 GWh due to higher unplanned outages at Alberta Thermal and Genesee 3, partially offset by increased merchant production resulting from the Unit 4 uprate at our Sundance facility.

Gross margin for the year ended Dec. 31, 2009 decreased $42 million ($1.00 per installed MWh) due to higher planned outages at Alberta Thermal and lower hydro volumes and prices, partially offset by lower planned and unplanned outages at Genesee 3, an adjustment to prior period indices, lower penalties due to lower spot prices, and higher wind volumes due to the acquisition of Canadian Hydro.

In 2008, gross margin decreased $64 million ($1.67 per installed MWh) due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher coal costs, partially offset by favourable pricing and higher merchant volumes due to the uprate on Unit 4 of our Sundance facility.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities, five hydro facilities, and five wind farms with a total gross generating capacity of 1,356 MW (1,218 MW net ownership interest). All of our facilities in Eastern Canada earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Our Windsor facility also sells a portion of its production on the merchant spot market.

For the year ended Dec. 31, 2009, production increased 539 GWh primarily due to higher wind volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills.

In 2008, production decreased 485 GWh, primarily due to higher planned outages and lower market heat rates at Sarnia.

For the year ended Dec. 31, 2009, gross margins increased $53 million ($3.74 per installed MWh) due to higher wind volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills, and the new agreement with the OPA at our Sarnia regional cogeneration power plant.

In 2008, gross margins were comparable to the same period in 2007.

International

Our international assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,015 MW and natural gas- and diesel-fired assets in Australia with a generating capacity of 300 MW. 385 MW of our United States assets are operated by CE Gen, a joint venture in which we have a 50 per cent interest.

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

For the year ended Dec. 31, 2009, production decreased 1,773 GWh due to higher unplanned outages and higher economic dispatching at Centralia Thermal, and the expiration of the long-term contract at Saranac, partially offset by lower planned outages at Centralia Thermal.

In 2008, production increased 15 GWh due to lower unplanned outages and lower derates at Centralia Thermal (in 2007 we conducted test burns of PRB coal), partially offset by higher planned outages as a result of equipment modifications made at Centralia Thermal and economic dispatching at Centralia Thermal in the second quarter.

For the year ended Dec. 31, 2009, gross margins decreased $28 million ($0.83 per installed MWh) due to the expiration of the long-term contract at Saranac, higher coal costs, and lower production at Centralia Thermal, partially offset by favourable foreign exchange, favourable pricing, and favourable mark-to-market movements.

In 2008, gross margins increased $77 million ($3.97 per installed MWh) compared to the same period in 2007 primarily due to favourable pricing and mark-to-market movements.

The long-term contract between our Saranac facility and New York State Electric and Gas expired in June 2009. The facility now operates under a combined capacity and merchant dispatch contract. As the facility is depreciated on a unit of production basis, there is a corresponding $11 million decrease in depreciation expense from this lower level of production for the year ended Dec. 31, 2009. Further, as a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. Therefore, the net pre-tax earnings impact of this event is approximately $12 million for the year ended Dec. 31, 2009.

Operations, Maintenance, and Administration

For the year ended Dec. 31, 2009, OM&A expenses increased primarily due to higher planned outages, unfavourable foreign exchange rates, and the acquisition of Canadian Hydro, partially offset by targeted cost savings.

In 2008, OM&A expenses increased compared to the same period in 2007 due to cost escalations and higher planned maintenance costs.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed, excluding CE Gen:

Year ended Dec. 31	2009	2008	2007
Capitalized	**115**	125	78
Expensed	**118**	68	54
	233	193	132
GWh lost	**3,732**	3,478	2,056

Production lost as a result of planned maintenance in the year ended Dec. 31, 2009 increased by 254 GWh primarily due to the uprate on Unit 5 at our Sundance facility. In 2008, production lost increased by 1,422 GWh primarily due to the Unit 2 boiler modifications at Centralia Thermal.

For the year ended Dec. 31, 2009, total planned maintenance costs increased compared to the same period in 2008 due to higher planned outages across the fleet and cost escalations.

In 2008, total planned maintenance costs increased compared to 2007 due to the Unit 2 boiler modifications at Centralia Thermal, higher planned outages across the fleet, and cost escalations.

Depreciation Expense

For the year ended Dec. 31, 2009, depreciation expense increased due to an increased asset base, unfavourable foreign exchange rates, and the retirement of certain assets that were not fully depreciated during planned maintenance activities, partially offset by lower production at Saranac and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal in 2008.

In 2008, depreciation expense increased compared to 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal.

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

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

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

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

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

The results of the COD segment, with all trading results presented net, are as follows:

Year ended Dec. 31	2009	2008	2007
Gross margin	**47**	105	55
Operations, maintenance, and administration	**31**	53	34
Depreciation and amortization	**4**	3	1
Intersegment cost allocation	**(32)**	(30)	(27)
Operating expenses	**3**	26	8
Operating income	**44**	79	47

For the year ended Dec. 31, 2009, COD gross margins decreased due to a reduction in industrial demand, gas price uncertainty, and the change in the California market, which resulted in reduced pricing spreads and smaller margins.

In 2008, gross margins increased due to all regions experienced positive results in 2008, with the increase primarily attributable to successful trading strategies involving regional power demand and price differentials in the eastern region.

For the year ended Dec. 31, 2009, OM&A expenses decreased due to a reduction in both discretionary expenditures and staff compensation costs. In 2008, OM&A expenses increased primarily due to additional trading compensation as a result of increased gross margins.

The inter-segment cost allocations have increased slightly in both 2009 and 2008 due to an increase in the work performed on behalf of the Generation segment.

NET INTEREST EXPENSE

Year ended Dec. 31	2009	2008	2007
Interest on long-term debt	**183**	177	171
Interest income from tax settlement	**–**	(30)	–
Interest income	**(6)**	(16)	(32)
Capitalized interest	**(36)**	(21)	(6)
Other	**3**	–	–
Net interest expense	**144**	110	133

Net interest expense increased for the year ended Dec. 31, 2009 due to higher debt levels and lower interest income as a result of the receipt of interest income from a tax settlement in 2008, partially offset by lower interest rates and higher capitalized interest primarily due to the construction of Keephills 3.

In 2008, $30 million of reported interest income reflects a refund resulting from the receipt of a tax settlement in 2008 in connection with outstanding tax issues related to prior periods.

For the year ended Dec. 31, 2008, net interest expense decreased primarily due to interest income received on the settlement of the tax issue discussed above and higher capitalized interest, partially offset by lower interest income from cash deposits.

OTHER INCOME

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

During 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.

NON-CONTROLLING INTERESTS

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in five natural gas-fired and one coal-fired generating facility with a total gross generating capacity of 814 MW. Stanley Power owns the minority interest in TA Cogen. Our CE Gen joint venture investment includes a 75 per cent ownership of Saranac, a 320 MW natural gas-fired cogeneration facility in New York. Natural Forces owns a 17 per cent interest in our Kent Hills facility, which operates 96 MW of wind assets. Since we own a controlling interest in TA Cogen and Kent Hills, we consolidate the entire earnings, assets, and liabilities in relation to our ownership of those assets. For Saranac, we proportionately consolidate our share of the earnings, assets, and liabilities in relation to our ownership.

Non-controlling interests on the Consolidated Statements of Earnings and Consolidated Balance Sheets relate to the earnings and net assets attributable to TA Cogen, Saranac, and Kent Hills that are not owned by us. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen, Saranac, and Kent Hills is shown as distributions paid to subsidiaries' non-controlling interests in the financing section.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2009 decreased due to lower earnings at CE Gen as a result of the expiration of the long-term contract at our Saranac facility, and lower earnings at TA Cogen.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2008 increased due to higher earnings at TA Cogen and CE Gen.

EQUITY LOSS

As required under Accounting Guideline 15, Consolidation of Variable Interest Entities, of the Canadian Institute of Chartered Accountants ("CICA"), our previously held Mexican operations were accounted for as an equity investment. On Oct. 8, 2008, we successfully completed the sale of our Mexican operations to InterGen for a sale price of $334 million. The sale included the plants and all associated commercial arrangements. Refer to the Significant Events section for further details.

For the year ended Dec. 31, 2008, equity loss reflected the writedown of our Mexican equity investment in the first quarter of 2008.

INCOME TAXES

Income tax expense under Canadian GAAP is based on the earnings of the period, the jurisdiction in which the income is earned, and if there are any differences between how pre-tax income is calculated under Canadian GAAP versus income tax law. Income tax rates and amounts differ based upon these factors. When calculating income tax expense, if there is a difference from when an expense or revenue is recognized under either accounting or income tax rules, we make an estimate of when in the future this difference will no longer be in effect and the anticipated income tax rate at that time. These items are deductible or taxable temporary differences. We base these tax rates upon the rates the government expects to be in effect when these temporary differences reverse.

Therefore, when a government announces a change in future income tax rates, it will affect the anticipated income tax asset or liability that will appear in our financial statements.

A reconciliation of income tax expense and effective tax rates is presented below:

Year ended Dec. 31	2009	2008	2007
Earnings before income taxes	**196**	258	329
Equity loss	**–**	(97)	(50)
Other income	**7**	5	16
Earnings before income taxes, equity loss, and other income	**189**	350	363
Income tax expense	**15**	23	20
Income tax expense on other income	**(1)**	(1)	(4)
Income tax recovery recorded on the sale of our Mexican equity investment	**–**	35	–
Income tax recovery related to tax positions	**–**	15	18
Income tax recovery related to change in future tax rates	**5**	–	48
Income tax expense excluding equity loss and other items	**19**	72	82
Effective tax rate on earnings before income taxes, equity loss, and other items[1] (%)	**10**	21	23

1 To present comparable reconciliations, prior years' effective tax rate analyses were calculated based on earnings before income tax, equity loss, and other income.

During 2008 and 2007, we settled certain taxation issues with the associated taxation authorities. As a result, we recorded a future income tax recovery of $15 million and $18 million, respectively, related to these items.

As a result of a reduction in Canadian corporate income tax rates expected to apply to future tax liabilities, income tax expense was reduced by $5 million and $48 million in 2009 and 2007, respectively.

In 2008, we recorded a tax recovery of $35 million related to the sale of our Mexican equity investment.

Adjusting for the items mentioned above, income tax expense decreased for the year ended Dec. 31, 2009 due to lower pre-tax earnings and the recovery recorded for a change in future tax rates related to tax liabilities recorded in prior periods, partially offset by the tax recovery related to tax positions recorded in 2008. For the year ended Dec. 31, 2008, the adjusted income tax expense decreased compared to 2007 due to lower pre-tax income.

The effective tax rate on earnings before income taxes, equity loss, and other items decreased for the years ended Dec. 31, 2009 and 2008 primarily due to a change in pre-tax earnings and certain deductions that do not fluctuate with earnings.

FINANCIAL POSITION

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

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	32	Acquisition of Canadian Hydro and the timing of operational payments
Accounts receivable	(84)	Timing of customer receipts and lower revenues
Income taxes receivable	(22)	Recovery of tax prepayments and overpayments
Inventory	39	Lower production, economic dispatching, and cost increases
Long-term receivable	35	Deposit made with tax authorities for a dispute not expected to be settled within one year
Risk management assets (current and long-term)	(53)	Price movements
Property, plant, and equipment, net	1,544	Acquisition of Canadian Hydro and capital additions, partially offset by depreciation expense and foreign exchange
Goodwill	292	Acquisition of Canadian Hydro
Intangible assets	120	Acquisition of Canadian Hydro, partially offset by amortization expense
Other assets	63	Acquisition of Canadian Hydro, combined with new growth and productivity initiatives
Accounts payable and accrued liabilities	(137)	Timing of payments and lower operational and construction expenditures
Collateral received	62	Collateral collected from counterparties associated with their obligations as a result of a change in forward prices
Long-term debt (including current portion)	1,634	Issuance of long-term debt due to the acquisition of Canadian Hydro and increased draws on credit facilities, partially offset by foreign exchange and maturities
Risk management liabilities (current and long-term)	(127)	Price movements
Asset retirement obligation (including current portion)	(15)	Favourable foreign exchange movement
Net future income tax liabilities (including current portions)	114	Acquisition of Canadian Hydro and tax effect on the increase in net risk management assets
Shareholders' equity	419	Issuance of common shares, net earnings, and movements in AOCI, partially offset by dividends declared

FINANCIAL INSTRUMENTS

Financial instruments are used to manage our exposure to interest rates, commodity prices, currency fluctuations, as well as credit and other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives, which are described below. Financial instruments are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, these changes in fair value will not affect earnings until the financial instrument is settled. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the Consolidated Balance Sheets as risk management assets and liabilities.

We have two types of financial instruments: (1) those that are used in the COD and Generation segments in relation to Energy Trading activities, commodity hedging activities, and other contracting activities and (2) those used in the hedging of debt, projects, expenditures, and the net investment in self-sustaining foreign operations. The majority of the derivatives traded by the Corporation are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives have been determined using valuation techniques or models.

The majority of our financial instruments and physical commodity contracts are recorded under normal purchase / normal sale accounting or qualify for, and are recorded under, hedge accounting rules. As a result, for those contracts for which we have elected hedge accounting, no gains or losses are recorded through the Consolidated Statements of Earnings as a result of differences between the contract price and the current forecast of future prices. We record the changes in fair value of these contracts through the Consolidated Statements of Other Comprehensive Income ("OCI"). When these contracts are settled, the value previously recorded in OCI is reversed and we receive the contracted cash amount for those contracts.

Under hedge accounting rules we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. For commodity contracts, this testing ensures that the amount of electricity we have contracted to supply or natural gas contracted to buy is still likely to be provided. For financial instruments related to debt and projects, this testing ensures that the amount we have contracted to pay for long-term financing and capital projects has remained consistent in terms of timing and amounts. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. Where hedges are effective, that is, it is reasonable that we will fulfill that contract without having to purchase commodities in the market, we continue the accounting treatment described above. Where hedges are ineffective, that is, we will be required to fulfill that contract with commodities purchased in the market, these hedges, in total or in part, are considered ineffective. The ineffective portion is no longer recorded as a hedge and the changes in fair value are recorded in income and no longer through OCI.

As well, there are certain contracts in our portfolio that at their inception do not qualify for, or we have chosen not to elect, hedge accounting. For these contracts we recognize mark-to-market gains and losses in the Consolidated Statements of Earnings resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not affect the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

Our financial instruments are categorized as fair value hedges, cash flow hedges, net investment hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

Fair Value Hedges

Fair value hedges are used to offset the impact of fluctuations in the foreign currency and interest rates on various assets and liabilities. Interest rate swaps are used to hedge exposures in the fair value of long-term debt caused by variations in market interest rates by fixing interest rates. Foreign exchange contracts are used to hedge certain foreign currency denominated assets and liabilities. Based on the fair value of risk management assets and liabilities at Dec. 31, 2009, approximately six per cent of our financial instruments are fair value hedges.

All gains or losses related to fair value hedges are recorded on the Consolidated Statements of Earnings, which, in turn, are completely offset by the value of the gains or losses related to the hedged risk of the debt instruments on the foreign currency denominated assets and liabilities.

A summary of how typical fair value hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)	✓	–	✓	–
Settle contract	✓	–	✓	✓

1 Option contracts may require an upfront cash investment.

Cash Flow Hedges

Cash flow hedges are categorized as project or commodity hedges and are used to offset foreign exchange and commodity price exposures on long-term projects as a result of market fluctuations. These contracts have a maximum duration of five years. Based on the fair value of risk management assets and liabilities at Dec. 31, 2009, approximately 91 per cent of our financial instruments are cash flow hedges.

Project Hedges

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. When project hedges qualify for, and we have elected to use hedge accounting, the gains or losses related to these contracts in the periods prior to settlement are recorded in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the financial instruments, any gain or loss on the contracts is included in the cost of the related asset and depreciated over the asset's estimated useful life.

A summary of how typical project hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract	–	–	–	–
Reporting date (marked-to-market)[1]	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓

1 *Any ineffective portion is recorded in the Consolidated Statements of Earnings.*

Commodity Hedges

Physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. When commodity hedges qualify for, and we have elected to use hedge accounting, the fair value of the hedges is recorded in risk management assets or liabilities with changes in value being reported in OCI, up until the date of settlement. The fair value of the majority of our commodity hedges are calculated using adjusted quoted prices from an active market and/or the input is validated by broker quotes. Upon settlement of these financial instruments, the amounts previously recognized in OCI are reclassified to net earnings.

Our physical commodity contracts are designated as all-in-one hedges and result in a net asset or liability position on our Consolidated Balance Sheets. Upon physical delivery of the commodity, we receive a gross settlement at the contracted price. Upon receipt of payment, the related net risk management asset or liability is eliminated. If an all-in-one hedge contract cannot be settled by physical delivery of the underlying commodity, it will be settled financially.

A summary of how typical commodity hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)[2]	–	✓	✓	–
Settle contract	✓	✓	✓	✓

1 *Option contracts may require an upfront cash investment.*

2 *Any ineffective portion is recorded in the Consolidated Statements of Earnings.*

During the year, the change in the position of financial instruments to a net asset position is primarily a result of changes in future prices on contracts in our Generation segment. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding fair valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2008.

In limited circumstances, we may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under Canadian GAAP as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, therefore fair value is determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally-developed fundamental price forecast is used in the valuation. Fair values are validated 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 Dec. 31, 2009, Level III instruments had a net liability carrying value of $26 million. For the year ended Dec. 31, 2009, a realized gain of $1 million was included in earnings before income taxes relating to those Level III instruments.

For both project and commodity cash flow hedges, when we do not elect for hedge accounting, or the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices or exchange rates related to these financial instruments are recorded through the Consolidated Statements of Earnings and Retained Earnings in the period the gain or loss occurs.

Net Investment Hedges

Cross-currency interest rate swaps, foreign currency forward contracts, and foreign currency debts can be used to hedge exposure to changes in the carrying values of our net investments in foreign operations having functional currency other than the Canadian dollar. Foreign denominated expenses are also used to assist in managing foreign currency exposures on earnings from self-sustaining foreign operations. Based on the fair value of risk management assets and liabilities at Dec. 31, 2009, approximately two per cent of our financial instruments are net investment hedges.

Since net investment hedges qualify for hedge accounting, gains or losses related to net investment hedges are recorded in OCI until there is a reduction in the net investment of the foreign operation. Net investment hedges are short-term in nature related to the underlying investment, therefore contracts must be routinely renewed. As each of the short-term contracts mature or is settled, cash inflows or outflows result that are recorded in investing activities on the Consolidated Statements of Cash Flows to reconcile the difference between contracted rates and market rates at the date of settlement. If there is a reduction in the net investment of the foreign operation, the gains or losses previously recorded in OCI are transferred to net earnings in that period.

A summary of how typical net investment hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract	–	–	–	–
Reporting date (marked-to-market)	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓
Reduction of net investment of foreign operation	✓	✓	✓	–

Non-Hedges

We use natural hedges as much as possible, such as U.S. interest rates on our U.S.-denominated long-term debt, to offset any exposures related to changes in foreign exchange rates. Financial instruments not designated as hedges are used to reduce currency risk on the results of our foreign operations due to the fluctuation of exchange rates beyond what is naturally hedged. All gains or losses related to non-hedges are recorded in the Consolidated Statements of Earnings as they do not qualify for, nor have they been designated for, hedge accounting. Based on the fair value of risk management assets and liabilities at Dec. 31, 2009, approximately one per cent of our financial instruments are non-hedges.

A summary of how typical non-hedges are recorded in our financial statements is as follows:

Event	Consolidated Statements of Earnings	Consolidated Statements of Comprehensive Income	Consolidated Balance Sheets	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	✓	–
Reporting date (marked-to-market)	✓	–	✓	–
Roll-over into new contract	✓	–	✓	✓
Settle contract	✓	–	✓	✓
Divest contract	✓	–	✓	✓

1 Some contracts may require an initial cash investment.

EMPLOYEE SHARE OWNERSHIP

We employ a variety of stock-based compensation plans to align employee and corporate objectives. On Feb. 1, 2008, one million stock options were granted at an exercise price of $31.97, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$31.83, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2009 and expire on Feb.1, 2019. The conversion of these options is not dilutive.

On Feb. 22, 2010, we had 2.3 million outstanding employee stock options with a weighted average exercise price of $25.01.

At Dec. 31, 2009, 1.5 million options to purchase our common shares were outstanding with a weighted average exercise price of $26.36, and 0.9 million were exercisable at the reporting date. For the year ended Dec. 31, 2009, no options were exercised and 0.1 million options were cancelled with a weighted average exercise price of $29.88.

At Dec. 31, 2008, 1.6 million options to purchase our common shares were outstanding with a weighted average exercise price of $27.06, and 0.6 million were exercisable at the reporting date. For the year ended Dec. 31, 2008, 0.3 million options with a weighted average exercise price of $20.52 were exercised resulting in 0.3 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $27.96.

Under the terms of the Performance Share Ownership Plan ("PSOP"), certain employees receive grants which, after three years, make them eligible to receive a set number of common shares or the equivalent value in cash plus dividends based upon our performance relative to companies comprising the comparator group. After three years, once PSOP eligibility has been determined and if common shares are granted, 50 per cent of the common shares are released to the participant and the remaining 50 per cent are held in trust for one additional year. The granting of common shares under the PSOP plan is not dilutive.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below senior manager level for up to 30 per cent of the employee's base salary for the purchase of our common shares from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. At Dec. 31, 2009, accounts receivable from employees under the plan totalled $3 million (2008–$3 million). This program is not available to officers and senior management.

EMPLOYEE FUTURE BENEFITS

We have registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options. In Canada, there is a supplemental defined benefit plan for Canadian-based defined contribution members whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plan ceased for new employees on June 30, 1998. The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2009.

We provide other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2007.

The supplemental pension plan is an obligation of the corporation. We are not obligated to fund the supplemental plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $58 million to secure the obligations under the supplemental plan.

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2009 and 2008:

Year ended Dec. 31	2009	2008	Explanation of change
Cash and cash equivalents, beginning of year	**50**	51	
Provided by (used in):			
Operating activities	**580**	1,038	Decrease in cash earnings of $99 million and unfavourable changes in working capital of $359 million.
Investing activities	**(1,598)**	(581)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million and the sale of our Mexican equity investment in 2008 for $332 million, partially offset by a decrease in capital spending of $102 million and an increase in collateral received from counterparties of $87 million.
Financing activities	**1,053**	(467)	Increase in draws on credit facilities of $863 million, increase in proceeds from issuance of long-term debt of $617 million, increase in proceeds from issuance of common shares of $382 million, and the purchase of common shares under the NCIB program in 2008 of $130 million, partially offset by a $488 million increase in the repayment of long-term debt.
Translation of foreign currency cash	**(3)**	9	
Cash and cash equivalents, end of year	**82**	50	

Year ended Dec. 31	2008	2007	Explanation of change
Cash and cash equivalents, beginning of year	51	66	
Provided by (used in):			
Operating activities	1,038	847	Increase in cash earnings of $47 million and favourable changes in working capital of $144 million primarily due to the timing of PPA receipts in 2008.
Investing activities	(581)	(410)	Additional capital spending of $407 million, and a decrease in realized gains on financial instruments of $55 million, partially offset by proceeds from the sale of our Mexican equity investment of $332 million.
Financing activities	(467)	(444)	Increase in repayments of short-term debt of $532 million and long-term debt of $56 million, and a $55 million increase to repurchase common shares under the NCIB program, partially offset by the issuance of $500 million of long-term debt in 2008 and the redemption of preferred shares of $175 million in 2007.
Translation of foreign currency cash	9	(8)	
Cash and cash equivalents, end of year	50	51	

LIQUIDITY AND CAPITAL RESOURCES

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

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

Debt

Recourse and non-recourse debt totalled $4.4 billion at Dec. 31, 2009 compared to $2.8 billion at Dec. 31, 2008. Total long-term debt increased from Dec. 31, 2008 primarily due to the debt issued during the fourth quarter of 2009 to fund the acquisition of Canadian Hydro and growth expenditures.

Credit Facilities

We have a total of $2.1 billion of committed long-term credit facilities of which $0.7 billion is not drawn and is available as of Dec. 31, 2009, subject to customary borrowing conditions. At Dec. 31, 2009, credit utilized under these facilities is $1.4 billion, which is comprised of actual drawings of $1.1 billion and of letters of credit of $334 million. Amounts drawn on credit facilities increased in 2009 as a result of lower cash earnings, partially offset by an increase in collateral received in 2009, which was used to repay credit facility balances.

Beyond the cash flow generated by our business, our primary source for short-term liquidity requirements is from our $2.1 billion of committed credit facilities. These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2012, with the remainder comprised of bilateral credit facilities which mature between 2011 and 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Share Capital

On Feb. 22, 2009, we had 219 million common shares outstanding.

Normal Course Issuer Bid Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval from the Toronto Stock Exchange to purchase, for cancellation, up to 9.9 million of our common shares representing five per cent of our 198 million common shares issued and outstanding as at April 30, 2009. 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 year ended Dec. 31, 2009, no shares were purchased under the NCIB program.

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 Dec. 31, 2009, we provided letters of credit totalling $334 million (2008 – $430 million) and cash collateral of $27 million (2008 – $37 million). The decrease in letters of credit and cash collateral is due primarily to lower forward electricity prices in the Pacific Northwest and reduced trading activity with exchanges. These letters of credit and cash collateral secure certain amounts included on our Consolidated Balance Sheets under "Risk Management Liabilities" and "Asset Retirement Obligation".

Working Capital

At Dec. 31, 2009, the excess of current liabilities over current assets is $5 million (2008–$287 million). The excess of current liabilities over current assets decreased $282 million compared to 2008 due to a reduction in the current portion of long-term debt, the timing of operational commitments, and an increase in net risk management assets, partially offset by lower revenues and an increase in collateral received from counterparties.

Capital Structure

Our capital structure consisted of the following components as shown below:

As at Dec. 31	2009		2008	
	Amount	%	Amount	%
Debt, net of cash and cash equivalents	**4,360**	**56**	2,758	48
Non-controlling interests	**478**	**6**	469	8
Common shareholders' equity	**2,929**	**38**	2,510	44
	7,767	**100**	5,737	100

Contractual repayments of fixed price gas purchase contracts, transmission, operating leases, commitments under mining agreements, commitments under long-term service agreements, long-term debt and the related interest, and growth project commitments are as follows:

	Fixed price gas purchase contracts	Transmission	Operating leases	Coal supply and mining agreements	Long-term service agreements	Long-term debt[1]	Interest on long-term debt[2]	Growth project commitments	Total
2010	8	–	10	51	14	29	224	497	833
2011	7	2	10	47	16	251	203	87	623
2012	7	3	9	47	16	1,090	183	14	1,369
2013	7	3	9	47	16	659	170	–	911
2014	7	3	8	51	16	231	142	–	458
2015 and thereafter	25	38	56	269	18	2,203	600	–	3,209
Total	**61**	**49**	**102**	**512**	**96**	**4,463**	**1,522**	**598**	**7,403**

1 Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature in 2012 and 2013.

2 Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.

OFF-BALANCE SHEET ARRANGEMENTS

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such off-balance sheet arrangements.

CLIMATE CHANGE AND THE ENVIRONMENT

The varieties of combustible fuels used to generate electricity all have some impact on the environment. While we are pursuing a climate change strategy that includes, among other elements, investing in renewable energy resources such as wind and hydro, we believe that coal and natural gas as fuels will continue to play an important role in meeting the energy needs of the future. We place significant importance on environmental compliance while seeking to deliver low cost electricity.

Ongoing and Recently Passed Environmental Legislation

While we continue to pursue clean coal and other technologies to reduce the impact of our power generating activities upon the environment, changes in current environmental legislation do have, and will continue to have, an impact upon our business.

Canada

In December 2009, the Copenhagen Accord ("The Accord") on climate change was negotiated and announced. The Accord is not binding nor does it stipulate a global target for GHG reductions, but rather countries are left to determine their individual targets and policies to manage emissions. The federal government's previously-announced goal of a 17 per cent GHG reduction from a 2005 baseline by 2020 remains the target. However, the federal government has not yet implemented a framework or regulations to achieve those goals. At this point, it appears that the details and schedule of the Canadian program will depend on the development and direction of the U.S. approach.

Separately, the Government of Canada announced its intent to develop new Canadian air pollutant requirements for sulphur dioxide, nitrogen oxide ("NO_x"), and mercury. Stakeholder consultations involving industry, provincial and federal governments, and environmental organizations are underway; however there is currently no defined date for the finalization and implementation of any recommendations.

On Dec. 1, 2009, the Government of Ontario released its mandatory GHG reporting regulation, requiring industrial facilities with more than 25,000 tonnes of carbon dioxide ("CO_2") emissions per year to report annually. The first reporting deadline for 2010 emissions is June 2011. This regulation is intended to lay the groundwork for an Ontario-based GHG regulatory framework to be implemented in 2010.

Alberta continues to maintain its GHG regulatory regime which requires reductions of 12 per cent in emission intensity from a 2003-2005 average baseline. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover these compliance costs from our PPA customers. For 2009, after flow-through, our annual net GHG compliance costs are less than $4 million (2008–less than $2 million). We continue to examine compliance options, including additions to our offsets portfolio to minimize our compliance risk beyond the expiration of our PPAs.

United States

The American Clean Energy and Security Act was passed in June 2009, which established a cap and trade system designed to achieve a 17 per cent reduction in GHG emissions by 2020. There is significant uncertainty regarding the form and schedule of legislation that will be developed as a result of the cap and trade system designed, or if legislation will even emerge in 2010.

Meanwhile, the U.S. Environmental Protection Agency ("EPA") is pursuing a separate path to regulate GHGs under the Clean Air Act. In November 2009, the U.S. courts upheld the endangerment finding which determines that CO_2 is a pollutant and therefore able to be regulated by the EPA under the Clean Air Act. How and when a legislative option will develop versus the EPA regulatory approach is uncertain. In September 2009, the EPA separately announced requirements for nationwide GHG reporting beginning in 2010.

In Washington State in May 2009, Governor Gregoire signed an Executive Order laying out the state's plan for addressing climate change related emissions. In the Order the Governor included a directive to the State Department of Ecology to work with us to apply the state's GHG performance standard for power generation to the Centralia plant no later than 2025. That standard would require emissions reductions of approximately 0.5 tonnes/MWh, or about half of what is currently emitted at Centralia. Exploratory discussions are underway with the Department of Ecology to examine opportunities to achieve this reduction in emissions. At this time it is not clear how the state's target and timeframe will endure should federal GHG legislation come into effect.

Also, in Washington State since September, there has been a public process to review a draft agreement between us and the state regarding our voluntary initiative to reduce NO_x and mercury emissions from the Centralia plant. Specifically, we have proposed to:

- Control NO_x emissions to a maximum of 0.24 lbs/million Btus of fuel input, and
- Reduce mercury emissions by 50 per cent from current levels

It is expected that Washington State will issue its final determination in the spring of 2010.

Legal Implications

There are currently no ongoing legal actions as a result of environmental legislation.

TransAlta Activities

We believe that climate change has the potential to impact the business environment in which we operate. Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We expect that increased scrutiny will be placed on environmental emissions and compliance, and we therefore have a proactive approach to minimizing risks to our results.

Our environment management programs encompass several elements:

- construction of renewable power sources;
- environmental controls and efficiency improvements;
- active participation in policy discussions;
- clean energy technology development including CCS; and
- investment in an offsets portfolio.

Renewable Power

In addition to our acquisition of Canadian Hydro, our investment in renewable power sources continues through the building of renewable power resources such as the Summerview 2, Kent Hills, and Ardenville wind farms. An increased renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or, in future, offsets.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We are installing mercury control equipment at our Alberta Thermal operations in 2010 in order to meet the province's 70 per cent reduction objectives. Our new Keephills 3 plant will use supercritical combustion technology to maximize thermal efficiency, as well as sulphur dioxide capture and low NO_x combustion technology.

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

Policy Participation

We are active in policy discussions at a variety of levels of government. These stakeholder negotiations have allowed us to engage in proactive discussions with governments and industry participants to meet environmental requirements over the longer-term.

CCS Development

On Oct. 14, 2009, the governments of Canada and Alberta announced that Project Pioneer, our CCS project, received committed funding of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of a FEED study that is expected to be complete in 2010 or early 2011. Once built, the prototype plant will be one of the largest CCS facilities in the world and the first to have an integrated underground storage system. The project will pilot Alstom Canada's proprietary chilled ammonia carbon capture technology and will be designed to capture one megatonne of CO_2 at one of our Alberta Thermal units. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site.

In addition, we look to advance other clean energy technologies through organizations such as the Canadian Clean Coal Power Coalition which examines emerging clean combustion technologies such as gasification. We are also part of a group of companies participating in the Integrated CO_2 Network to develop carbon capture and storage systems and infrastructure for Canada.

Offsets Portfolio

TransAlta maintains an offset portfolio with a variety of instruments than can be used for compliance purposes or otherwise banked or sold. We continue to examine additional emission offset opportunities that also allow us to meet emission targets at a competitive cost. We ensure that any investments in offsets will meet certification criteria in the market in which they are to be used.

Future Growth

In 2009, we estimate that 40 million tonnes of GHGs with an intensity of 0.900 tonnes/MWh (2008 – 38.5 million tonnes of GHGs with an intensity of 0.893 tonnes/MWh) were emitted as a result of normal operating activities[1]. Total GHG emissions increased in 2009 largely due to more dispatch variability at our Alberta Thermal operations leading to slightly lower combustion efficiencies. New generation growth and the related increase in emissions will be partially offset by the decommissioning of Unit 4 at our Wabamun plant. The various activities discussed above, including our investment in renewable power and CCS technology, are designed to minimize the environmental and financial impacts of the expected increase in emissions.

Our Board of Directors continues to monitor the results of our reduction efforts and future reduction plans to ensure we are compliant with existing environmental regulations and to ensure that we will be compliant with future legislation.

2010 OUTLOOK

BUSINESS ENVIRONMENT

Power Prices

In 2010, power prices are expected to remain at or slightly above 2009 levels due to the influence of low natural gas prices and minimal demand growth. In the Alberta market, the longer-term fundamentals of the market remain strong and the recovery of the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices is the main driver behind the recovery of power prices. Natural gas prices are expected to remain low until 2011.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has expressed its plan to coordinate the timing and structure of its regulatory framework with the U.S. In the U.S., it is not clear if climate change legislation will prevail or if instead regulation will be applied by the EPA. Each of these outcomes could create widely different results for the energy industry in the U.S., and indirectly for Canada's regulatory approach.

We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

Economic Environment

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

A number of our financial and industrial counterparties have experienced credit rating downgrades and we expect 2010 will continue to be challenging for some of our counterparties. While we had no counterparty losses in 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.

OPERATIONS

Capacity, Production, and Availability

Generating capacity is expected to increase in 2010 due to the commissioning of Summerview 2 and Kent Hills 2. Overall production and availability for 2010 is expected to increase compared to 2009 due to lower planned and unplanned outages across the fleet, and the acquisition of Canadian Hydro. Overall fleet availability for 2010 is expected to be approximately 90 per cent.

Commodity Hedging

Through the Alberta PPAs and our other long-term contracts, approximately 75 per cent of our capacity is contracted over the next seven years. To provide further stability to future earnings, we enter into physical and financial contracts for periods of up to five years. As a result of the acquisition of Canadian Hydro, we also have various contracts with terms that extend beyond five years. Under this strategy, we target being up to 90 per cent contracted for the upcoming year, stepping down to 70 per cent in the fourth year. Approximately 89 per cent of our 2010 capacity is contracted with the average contracted price of \$60–\$65/MWh in Alberta and U.S.\$50–\$55/MWh in the Pacific Northwest.

1 2009 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO_2, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Coal costs for 2010, on a standard cost basis, are expected to increase five to 10 per cent compared to the prior year as a result of depreciation due to mine capital and higher diesel costs.

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

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America is expected to reduce the year to year volatility of prices going forward and may lead to greater opportunities to hedge our natural gas price exposure with longer term contracts.

In 2010, approximately 20 per cent of our fuel at our natural gas-fired facilities and seven per cent of our fuel at our coal-fired facilities is exposed to market fluctuations in energy commodity prices. We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Operations, Maintenance, and Administration Costs

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

Energy Trading

Earnings from our COD segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading to contribute between $50 million and $70 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 by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign currency expenses, including interest charges, which are used to largely offset our net foreign currency-denominated earnings.

Net Interest Expense

Net interest expense for 2010 is expected to be higher mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar to the U.S. dollar 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 expect to maintain $2.1 billion of committed credit facilities, and will monitor our exposures and obligations to ensure we have sufficient liquidity to meet our requirements.

Accounting Estimates

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of this MD&A, are based on the current economic environment and outlook. While we do not anticipate significant changes to these estimates as a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities. The unrealized gains or losses related to our risk management assets and liabilities are not expected to impact our cash flows as they are generally settled at contracted prices.

CAPITAL EXPENDITURES

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

Growth Capital Expenditures

In 2009, we successfully completed two of our growth capital projects, Blue Trail and the Sundance Unit 5 uprate. We have nine significant growth capital projects that are currently in progress with targeted completion dates between Q4 2010 and Q4 2012.

A summary of each of these significant projects is outlined below:

	Total Project		2009	2010		
Project	Estimated spend[1]	Incurred to date[1]	Actual spend[1]	Estimated spend[1]	Target completion date	Details
Keephills 3	988	707	231	225–245	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Blue Trail	113	113	87	–	Completed in Q4 2009	A 66 MW wind farm in southern Alberta
Sundance Unit 5 uprate	77	77	60	–	Completed in Q4 2009	A 53 MW efficiency uprate at our Sundance facility
Summerview 2	123	106	81	15–25	Completed in Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	1	1	5–10	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	1	1	0–5	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	27	27	95–105	Q1 2011	A 69 MW wind farm in southern Alberta
Bone Creek	48	4	4	40–45	Q1 2011	An 18 MW hydro facility in British Columbia
Kent Hills 2	100	18	18	80–85	Q4 2010	A 54 MW expansion of our wind farm in New Brunswick
Total growth	**1,652**	**1,054**	**510**	**460–520**		

1 Amounts are shown net of joint venture contributions.

Prior to our acquisition of Canadian Hydro, $23 million of costs were incurred in respect of Bone Creek, which do not form part of our total project cost.

Sustaining Capital Expenditures

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

Category	Description	Incurred in 2009	Expected cost
Routine capital	Expenditures to maintain our existing generating capacity	158	120–140
Productivity capital	Projects to improve power production efficiency	44	10–15
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	42	25–30
Centralia modifications	Capital project to convert to external coal	21	–
Planned maintenance	Regularly scheduled major maintenance	115	140–155
Total sustaining expenditures		380	295–340

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

	Coal	Gas	Renewables	Expected cost
Capitalized	70–75	45–50	25–30	140–155
Expensed	60–65	0–5	–	60–70
	130–140	45–55	25–30	200–225

	Coal	Gas	Renewables	Total
GWh lost	1,770–1,780	360–370	–	2,130–2,150

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, and capital markets. The funds required for committed growth and sustaining projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flow, our solid financial position, and the amount of capital available to us under existing committed credit facilities.

RELATED PARTY TRANSACTIONS

On Jan. 1, 2009, TAU and TransAlta Energy Corporation ("TEC") transferred certain generation and transmission assets to a newly formed internal partnership, TAGP, before amalgamating with TransAlta Corporation.

On Dec.16, 2006, predecessors of TAGP, a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power. 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 Dec. 31, 2009, TAGP had received $51 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

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

For the period November 2002 to November 2012, one of our 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. We entered into an offsetting contract and therefore have no risk other than counterparty risk.

RISK MANAGEMENT

Our business activities expose us to a wide variety of risks. Our goal is to manage these risks so that we are reasonably protected from an unacceptable level of earnings or financial exposure while still enabling business development. We use a multi-level risk management oversight structure to manage the risks arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface. As evidence of our dedication to excellent risk management and corporate governance, we were awarded both the Private Sector and Overall Conference Board of Canada/ Spencer Stuart National Award in Governance in 2009. For a further description of the following risk factors, refer to the Risk Factors section of our 2009 Annual Information Form.

The responsibilities of various stakeholders of our risk management oversight structure are described below:

THE BOARD OF DIRECTORS provides stewardship of the Corporation, establishes policies and procedures, defines risk tolerance as established under the Toronto Stock Exchange corporate governance guidelines, and receives an annual comprehensive Enterprise Risk Management ("ERM") review. The ERM reviews consist of a holistic view of the Corporation's inherent risks, how we mitigate these risks, and residual risks. It defines our risks, discusses who is responsible to manage each risk, how the risks are inter-related with each other, and identifies the applicable risk metrics. The Board of Directors also examines the ERM review in order to fulfill its requirement to understand the key risks of the Corporation and directs management to address any risk levels with which it believes are not optimal for shareholder value creation.

AUDIT AND RISK COMMITTEE ("ARC") established by the Board of Directors, provides assistance to the Board of Directors in fulfilling its oversight responsibility relating to the integrity of our financial statements and the financial reporting process, the systems of internal accounting and financial controls, the internal audit function, the external auditors' qualifications, terms and conditions of appointment, including remuneration, independence, performance and reports, and the legal and risk compliance programs as established by management and the Board of Directors. The ARC approves our Commodity Risk and Financial Exposure Management policies and reviews quarterly ERM reporting.

EXPOSURE MANAGEMENT COMMITTEE ("EMC") is chaired by our Chief Financial Officer and is comprised of the Chief Operating Officer, Vice-President and Treasurer, Vice-President of Finance and Controller, Vice-President Financial Operations, Vice-President Risk Management, Vice-President Commercial Operations, and Managing Director of Trading. The EMC is responsible for reviewing, monitoring, and reporting on our compliance with approved financial and commodity risk exposure management policies.

TECHNICAL RISK AND COMMERCIAL TEAM ("TRACT") is a committee chaired by the Vice-President, Project Management Office, and is comprised of our financial and operations vice presidents. It reviews major projects and commercial agreements at various stages through development, prior to submission for executive and Board approval.

CORPORATE TREASURY is responsible for the identification, management, monitoring, and reporting of financial risks, including: interest rate, foreign exchange, credit, liquidity, and insurable risks. The objective of Corporate Treasury is to maintain a strong financial position and a low cost of capital by sustaining a well capitalized balance sheet, mitigating earnings volatility, and maintaining ready access to capital markets. Our risk management policy requires that there be sufficient resources and training available to fulfill these objectives, including maintaining segregation of duties, all in accordance with risk management best practices.

RISK MANAGEMENT is staffed by experienced risk professionals who are responsible for ERM reporting to the Board and ARC, participating in risk identification, analysis, and reporting in major projects, analyzing commercial and environmental risk exposures in our assets and trading operations, as well as ensuring our daily market price exposure is kept within approved risk metrics, including VaR, position limits, term limits, and market limits. The Risk Management group uses a variety of processes and models to perform this analysis.

RISK CONTROLS

Our risk controls have several key components:

Enterprise Tone

Every corporate culture is unique. We strive to be more than unique by fostering beliefs and actions that are true to and respectful of our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainability, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a set of enterprise-wide policies that have been established to address key risks. These policies establish delegated authorities and limits for business transactions, as well as allow for an exceptional approval process. We perform periodic reviews and audits to ensure compliance with these policies.

Reporting

We regularly report risk exposures to key decision makers including the Board of Directors, senior management, and the EMC. This reporting to the EMC includes analysis of new risks, existing risk exposures, events that can affect these risks, and recommendations for any suggested course of action to mitigate the existing level of risk. This monthly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a system in place where employees, shareholders, or other stakeholders may report any potential ethical concerns. These concerns can be submitted anonymously, either directly to the ARC or to the Vice-President Internal Audit, who engages Corporate Security, Legal and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the ARC.

Value at Risk and Trading Positions

VaR is the most commonly used metric employed to track the risk of trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum loss over a specified period of time.

VaR is the primary measure used to manage COD's exposure to market risk resulting from trading activities. VaR is monitored on a daily basis, and is used to determine the potential change in the value of our marketing portfolio over a three-day period within a 95 per cent confidence level resulting from normal market fluctuations. Stress tests are performed weekly on both earnings and VaR to measure the potential effects of various market events that could impact financial results, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. The three day average VaR for the year ending Dec. 31, 2009 was $3 million compared to $6 million for the same period in 2008.

We estimate VaR using the historical variance/covariance approach. Currently, there are two accepted energy industry methodologies for estimating VaR: historical variance/covariance and monte carlo. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. See additional discussion under commodity price risk in the Risk Management section of this MD&A.

RISK FACTORS

Risk is inherent in all business activities and can never be entirely eliminated. However, shareholder value can be protected and enhanced by identifying, mitigating, monitoring, reporting, and where possible, insuring against these risks.

The following section addresses some, but not all, risk factors that could affect our future results and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

Certain sections will show the after-tax effect on net earnings and/or cash flows of changes in certain key variables. The analysis is based on business conditions and production volumes in 2009. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes.

Volume Risk

Volume risk relates to the variances from our expected production. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

Our hydro operations' financial performance is partially dependent upon the availability of water in a given year. The availability of water is difficult to forecast as it is primarily driven by weather. Such water availability introduces a degree of volatility in revenues earned by our hydro operations from year to year. This risk is complicated by obligations imposed within the PPA applicable to our Alberta hydro facilities. A monthly financial obligation must be paid to the PPA Buyer, based on a predetermined quantity of energy and ancillary services at market prices, regardless of our ability to generate such quantities. We carefully balance all of these factors together to achieve optimal productivity with the water resources available.

Our wind and geothermal operations are dependant upon the availability of wind and geothermal resources.

We manage these risks by:

- actively managing our assets and their condition through the Generation and Capital and Asset Reporting groups in order to be proactive in plant maintenance so that they are available to produce when market requires,
- monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities,
- placing our wind and geothermal facilities in locations that we believe to have sufficient resources in order for us to be able to generate sufficient electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require, and
- monitoring market volumes and liquidity to ensure sufficient volumes are available to fulfill proprietary trading requirements.

The sensitivities of volumes to our net earnings are shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	17

Generation Equipment and Technology Risk

Our plants are exposed to operational risks such as fatigue cracks in boilers, corrosion in boiler tubing, turbine failures, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we must either compensate the purchaser for the loss in the availability of production or record reduced electrical or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity.

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the output of our generating facilities for the longest period of time,
- performing preventative maintenance on a regular basis,
- adhering to a comprehensive plant maintenance program and regular turnaround schedules,
- adjusting maintenance plans by facility to reflect the equipment type and age,
- having sufficient business interruption insurance in place in the event of an extended outage,
- having force majeure clauses in the PPAs and other long-term contracts,
- using technology in our generating facilities that is selected and maintained with the goal of maximizing the return on those assets,
- monitoring technological advances and evaluating their impact upon our existing generating fleet and related maintenance programs,
- negotiating strategic supply agreements with selected vendors to ensure key components are available in the event of a significant outage
- entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts, and
- developing a long-term asset management strategy with the objective of maximizing the life cycles of our existing facilities and/or replacement of selected generating assets.

Commodity Price Risk

We have exposure to movements in certain commodity prices, including the market price of electricity and fuels used to produce electricity in both our electricity generation and proprietary trading businesses.

We manage exposure to fluctuations in gross margin associated with commodity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- entering into a variety of short- and long-term contracts to minimize our exposure to short-term fluctuations in electricity prices,
- purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit, and
- ensuring limits and controls are in place for our proprietary trading activities to ensure they are in line with our VaR methodologies.

In 2009, we had approximately 97 per cent of production under short-term and long-term contracts and hedges (2008–97 per cent). In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts.

We manage fuel price commodity risk by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants, and
- selectively using hedges, where available, to set prices for fuel.

We are exposed to increases in the cost of fuels used in production to the extent such increases are greater than the increases in the price that we can obtain for the electricity we produce. In 2009, 79 per cent (2008–82 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2008–100 per cent) of our purchased coal costs were contractually fixed.

We monitor the market for opportunities to enter into favourably priced long-term gas contracts.

The sensitivities of price changes to our net earnings are shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$1.00/MWh	7
Natural gas price	$0.10/GJ	2
Coal price	$1.00/tonne	14

Fuel Supply Risk

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities.

At Alberta Thermal, higher input costs, such as diesel, tires, the price of mining equipment, increased amounts of overburden being removed to access coal reserves, and mining operations moving further away from the power plants are all contributing to increased mining costs. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At Centralia Thermal, interruptions at our suppliers' mines and the availability of trains to deliver coal could affect our ability to generate electricity.

We manage fuel supply risk by:

- ensuring that the majority of the coal used in electrical generation is from coal reserves owned by us, thereby limiting our exposure to fluctuations in the supply of coal from third parties. As at Dec. 31, 2009, approximately 75 per cent (2008–70 per cent) of the coal used in generating activities is from coal reserves owned by us,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at Centralia Thermal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- contracting sufficient trains to deliver the coal requirements at Centralia Thermal,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,
- monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants, and
- hedging diesel exposure in mining and transportation costs.

We believe adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

Environmental Risk

Environmental risks are risks to our business associated with changes in environmental regulations or exposures. New emission reduction objectives for the power sector are being established by governments in Canada and the United States. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by imposing additional costs on the generation of electricity, such as emission caps, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental risk by:

- seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,
- having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety ("EHS") management system in place that is designed to continuously improve environmental performance,
- committing significant effort to work with regulators in Canada and the United States to ensure regulatory changes are well designed and cost effective,
- developing compliance plans that address how to meet or exceed emission standards for GHGs, mercury, sulphur dioxide and oxides of nitrogen, which will be adjusted as regulations are finalized,
- purchasing emission reduction offsets outside of our operations,
- investing in renewable energy projects, such as wind generation, and
- investing in clean coal technology development, which provides long-term promise for large emission reductions from fossil-fired generation.

We strive to maintain compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to our Board of Directors.

In 2009, we spent approximately $45 million (2008–$47 million) on environmental management activities, systems and processes.

We are a founder of the Canadian Clean Power Coalition, which is an industry consortium developed to assess and develop clean combustion technologies. On Oct. 14, 2009, the federal and provincial governments announced that Project Pioneer, our CCS project, has received committed funding of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative.

Credit Risk

Credit risk is the risk to our business associated with changes in creditworthiness of entities with which we have commercial exposures. This risk is in the ability of a counterparty to either fulfill their financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on creditworthiness of counterparties, define contract term limits, and credit concentration with any specific counterparty,
- using formal sign-off on contracts that include commercial, financial, legal, and operational reviews,
- using security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfill their obligation or go over their limits, and
- reporting our exposure using a variety of methods that allow key decision makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure such as requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

We took steps throughout 2009 to reduce our counterparty risk by proactively assessing the effect of the potential changes in the financial markets on counterparty risk and acting on these assessments. While we had no counterparty losses in 2009, we are continuing 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 for 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 from Dec. 31, 2008.

A summary of our credit exposure for commodity trading operations and hedging at Dec. 31, 2009 is provided below:

Counterparty credit rating	Net exposure
Investment grade	279
Non-investment grade	–
No external rating, internally rated as investment grade	23
No external rating, internally rated as non-investment grade	1

The maximum credit exposure to any one customer for commodity trading operations, excluding the California Independent System Operator and California Power Exchange, and including the fair value of open trading positions, is $63 million (2008–$105 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, and the acquisition of equipment and services from foreign suppliers. Our exposures are primarily to the U.S. and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged.

We manage our currency rate risk by:

- hedging our net investments in foreign operations using a combination of foreign-denominated debt and financial instruments. Our strategy is to offset 90 to 100 per cent of all foreign currency exposures. At Dec. 31, 2009, we have hedged approximately 97 per cent (2008–97 per cent) of our foreign currency net investment exposure, and
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies. We use financial instruments to hedge the balance of our exposure in foreign operations earnings.

Translation gains and losses related to the carrying value of our foreign operations are included in accumulated other comprehensive income ("AOCI") in shareholders' equity. At Dec. 31, 2009, the balance in AOCI represents a $126 million gain (2008–$61 million gain).

The sensitivity of changes in foreign exchange rates upon our net earnings is shown below:

Factor	Increase or decrease (foreign currency)	Approximate impact on net earnings
Exchange rate	$0.05	2

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide a more reliable and cost effective means to access capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,
- reporting liquidity risk exposure for proprietary trading activities on a regular basis to the EMC, senior management, and Board of Directors,
- maintaining investment grade credit ratings, and
- maintaining committed credit lines to support potential liquidity requirements.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our Alberta PPA plants. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

We manage interest rate risk by:

- employing a combination of fixed and floating rate debt instruments, and
- monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2009, approximately 31 per cent (2008 – 24 per cent) of our total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	1	10

Project Management Risk

As we are currently working on seven generating projects, we face risks associated with cost-overruns, delays, and performance.

We attempt to minimize these project risks by:

- ensuring all projects are vetted by the TRACT Committee so that projects have been highly scrutinized to see that established processes and policies are followed, risks have been properly identified and quantified, input assumptions are reasonable, and returns are realistically forecasted prior to Executive and Board approvals,
- using a consistent and disciplined project management methodology and processes,
- performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction,
- partnering with those who have previously been able to deliver projects economically and on budget. Our partnership with Capital Power on the construction of Keephills 3 is a direct result of this type of partnership,
- developing and following through with comprehensive plans that include critical paths identified, key delivery points, and backup plans,
- ensuring project closeouts so that any learnings from the project are incorporated into the next significant project,
- fixing the price and availability of the equipment, foreign currency rates, warranties, and source agreements as much as economically feasible prior to proceeding with the project, and
- entering into labour agreements to provide security around cost and productivity.

Human Resource Risk

Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

- potential disruption as a result of labour action at our generating facilities,
- reduced productivity due to turnover in positions,
- inability to complete critical work due to vacant positions,
- failure to maintain fair compensation with respect to market rate changes, and
- reduced competencies due to insufficient training, failure to transfer knowledge from existing employees, or insufficient expertise within current employees.

We manage this risk by:

- monitoring industry compensation and aligning salaries with those benchmarks,
- using incentive pay to align employee goals with corporate goals,
- monitoring and managing target levels of employee turnover, and
- ensuring new employees have the appropriate training and qualifications to perform their jobs.

In 2009, 46 per cent (2008–46 per cent) of our labour force is covered by 11 (2008–11) collective bargaining agreements. In 2009, five (2008–three) agreements were renegotiated. We anticipate negotiating four additional agreements in 2010. We do not anticipate any significant issues in the renewal of these agreements.

Regulatory and Political Risk

Regulatory and political risk describes the risk to our business associated with existing regulatory structures and the political influence upon those structures. This risk can come from market re-regulation, increased oversight and control, or other unforeseen influences. We are not able to predict whether there will be any changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business.

We manage these risks by working with governments, regulators, and other stakeholders to resolve issues. We are active in policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer-term.

International investments are subject to unique risks and uncertainties relating to the political, social, and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk

Access to transmission lines and sufficient capacity in those transmission lines are key in our ability to deliver power to our customers. However, with the continued growth in demand for electricity coupled with very little transmission capacity being added to existing infrastructures, the reduced reliability and capacity on the existing transmission facilities, and the risk associated with the existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continues to increase.

Reputation Risk

Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, and other entities.

We manage reputation risk by:

- striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders,
- clearly communicating our business objectives and priorities to a variety of stakeholders on a routine basis,
- maintaining positive relationships with various levels of government,
- pursuing sustainable development as a longer-term corporate strategy,
- ensuring that each business decision is made with integrity and in line with our corporate values, and
- communicating the impact and rationale of business decisions to stakeholders in a timely manner.

We are dedicated to operating a safe and ethical organization. We have a system in place where employees may report any potential ethical concerns. These concerns are directed to the Vice-President Internal Audit who engages Corporate Security, Legal, and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the ARC. All employees and directors are required to sign a corporate code of conduct on an annual basis.

Corporate Structure Risk

We conduct a significant amount of business through subsidiaries and partnerships. Our ability to meet and service debt obligations is dependent upon the results of operations of our subsidiaries and the payment of funds by our subsidiaries in the form of distributions, loans, dividends, or otherwise. In addition, our subsidiaries may be subject to statutory or contractual restrictions that limit their ability to distribute cash to us.

General Economic Conditions

Changes in general economic conditions impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of PP&E, results of financing efforts, credit risk, and counterparty risk.

Income Taxes

Our operations are complex, and located in different countries. The computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by Canadian GAAP, based on all information currently available.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	2

The effective tax rate on earnings before income taxes, equity loss, and other items for 2009 was 10 per cent. The effective income tax rate can change depending on the mix of earnings from various countries and certain deductions that do not fluctuate with earnings.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings which arise during the normal course of our business. We review 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 our favour, we do not believe that the outcome of any claims or potential claims of which we are currently aware will have a material adverse effect on us, taken as a whole.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 2009. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our significant accounting policies are described in Note 1 to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, financial instruments and hedges, PP&E, goodwill, income taxes, employee future benefits, and asset retirement obligation *(Notes 1(D), (F), (J), (K), (N), (O),* and *(Q)*, respectively). Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our ARC and our independent auditors. The ARC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

Tables are provided in the following discussion to reflect the sensitivities associated with changes in key assumptions used in the estimates. The tables reflect an increase or decrease in the percentage or other factor for each assumption. The inverse of each change is generally expected to have a similar opposite impact. Each separate item in the sensitivity assumes all other factors remain constant.

These critical accounting estimates are described below.

Revenue Recognition

The majority of our revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, availability incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each of these components is recognized upon output, delivery, or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments for each MWh produced at market prices and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts and futures contracts and options, to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting and are presented on a net basis in the Consolidated Statements of Earnings when hedge accounting is not applied. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the Consolidated Balance Sheets as risk management assets or liabilities. The fair value of derivative contracts receiving hedge accounting treatment open at the balance sheet date are deferred in the Consolidated Statements of Comprehensive Income and are presented on the Consolidated Balance Sheets as risk management assets or liabilities.

The determination of the fair value of Energy Trading contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility, and liquidity, among other factors. The majority of derivatives traded by us are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or models.

Financial Instruments

The fair value of financial instruments are determined and classified within three categories, which are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value.

Level I

Fair values in Level I are determined using inputs that are unadjusted quoted prices in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I Energy Trading fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange ("NYMEX").

Level II

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

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers in Level II. Level II fair values also include fair values determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, the Corporation uses inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third party information such as credit spreads. In 2009, the majority of our Level I financial instruments were reclassified as Level II, which is consistent with industry practice for similar valuation techniques.

Level III

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

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally-developed fundamental price forecast is used in the valuation.

As a result of the acquisition of Canadian Hydro, we also have various contracts with terms that extend beyond five years. Valuation of these contracts must be extrapolated as the lengths of these contracts make reasonably alternate fundamental price forecasts unavailable.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined at Dec. 31, 2009 is estimated to be +/- $24 million (2008–nil). This estimate is based on a +/- one standard deviation move from the mean where historical data is used in the valuation. Where an internally-developed fundamental price forecast is used, reasonably alternate fundamental price forecasts sourced from external consultants are included in the estimate. For contracts with terms that extend beyond five years, valuation must be extrapolated as the lengths of these contracts make reasonably alternate fundamental price forecasts unavailable.

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2009, PP&E makes up 78 per cent of our assets, of which 99 per cent relates to the Generation segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E and associated contracts are recoverable from future undiscounted cash flows. Factors which could indicate that impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner or use of the assets, the strategy for our overall business, and significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our businesses, the markets, and the business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of the future undiscounted cash flows from the asset. If the total of the undiscounted future cash flows (excluding financing charges, with the exception of plants that have specifically dedicated debt), is less than the carrying amount of the asset, an asset impairment charge must be recognized in our financial statements. The amount of the impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is best estimated by calculating the net present value of future expected cash flows related to the asset. Both the identification of events that may trigger impairment and the estimates of future cash flows and the fair value of the asset require considerable judgment.

The assessment of asset impairment requires management to make significant assumptions about future sales prices, cost of sales, production and fuel consumed over the life of the plants (up to 30 years), retirement costs, and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any change accounted for prospectively.

In estimating future cash flows of the plants, we use estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the plant. Actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

On an annual basis, or more frequently if events indicate, we perform an impairment review of our plants. As a result of this review in 2009, there were no changes to asset values.

Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are included in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the future costs are included in PP&E or investments. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to expense.

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. Major components of plants are depreciated over their own useful lives. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year.

In 2009, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $493 million (2008–$451million), of which $40 million (2008–$38 million) relates to mining equipment, and is included in fuel and purchased power.

The rates used are reviewed on an ongoing basis to ensure they continue to be appropriate, and are also reviewed in conjunction with impairment testing, as discussed above.

A five per cent change in the estimated useful life of depreciable assets will result in a change of $23 million in depreciation and amortization expense (2008–$22 million).

Valuation of Goodwill

We evaluate goodwill for impairment at least annually or more frequently if indicators of impairment exist. If the carrying value of a reporting unit, including goodwill, exceeds the reporting unit's fair value, any excess represents a goodwill impairment loss. A reporting unit is a portion of the business for which we can identify specific cash flows.

Goodwill was recorded on the acquisitions of Canadian Hydro, Merchant Energy Group of the Americas, Inc., Vision Quest Windelectric Inc., and CE Gen. At Dec. 31, 2009, this goodwill had a total carrying value of $434 million (2008–$142 million). The change in value from Dec. 31, 2008 is mainly due to the acquisition of Canadian Hydro.

We reviewed the recorded value of goodwill prior to year-end and determined that the fair values of our reporting units, based on historical cash flows and estimates of future cash flows, exceeded their carrying values. There were no significant events that impacted the fair values of the reporting units between the time of our testing and Dec. 31, 2009. This includes consideration of the current economic environment and related credit crisis, which does not materially impact the fair value of our assets and liabilities of our reporting units because they are highly contracted. Accordingly, no goodwill impairment charges were recorded for the year ended Dec. 31, 2009.

Determining the fair value of the reporting units is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins and fuel and operating costs. Had assumptions been made that resulted in fair values of the reporting units declining by 10 per cent from current levels, there would not have been any impairment of goodwill.

Income Taxes

In accordance with Canadian GAAP, we use the liability method of accounting for future income taxes and provide future income taxes for all significant income tax temporary differences.

Preparation of the consolidated financial statements requires an estimate of income taxes in each of the jurisdictions in which we operate. The process involves an estimate of our current tax exposure and an assessment of temporary differences resulting from differing treatment of items, such as depreciation and amortization, for tax and accounting purposes. These differences result in future tax assets and liabilities that are included in our Consolidated Balance Sheets.

An assessment must also be made to determine the likelihood that our future tax assets will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance must be determined. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Future tax assets of $221 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2009 (2008–$251 million). These assets are comprised primarily of unrealized losses from risk management transactions, asset retirement obligation costs, and net operating and capital loss carryforwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these deductions and carryforwards in the tax jurisdictions where they exist.

Future tax liabilities of $694 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2009 (2008–$610 million). These liabilities are comprised primarily of unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Judgment is required to assess continually changing tax interpretations, regulations and legislation, to ensure liabilities are complete and to ensure assets, net of valuation allowances, are realizable. The impact of different interpretations and applications could be material.

Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with Canadian GAAP based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the financial statements determinable.

Employee Future Benefits

We provide selected post-retirement benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liability for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The discount rate used reflects high-quality fixed income securities currently available and expected to be available during the period to maturity of the pension benefits. We do not expect to make any changes to the rate in 2010.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. For the year ended Dec. 31, 2009, the plan assets had a positive return of $38 million compared to a negative return of $55 million in 2008, and a positive return of $10 million in 2007. The 2009 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2008 and 2007.

Asset Retirement Obligation

We recognize ARO for PP&E in the period in which they are incurred if there is a legal obligation for us to reclaim the plant and/or site and if a reasonable estimate of a fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many ARO. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

At Dec. 31, 2009, the ARO recorded on the Consolidated Balance Sheets was $282 million (2008–$297 million). We estimate the undiscounted amount of cash flow required to settle the ARO is approximately $0.8 billion, which will be incurred between 2010 and 2072. The majority of the costs will be incurred between 2020 and 2030. An average discount rate of eight per cent was used to calculate the carrying value of the ARO.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	2
Undiscounted ARO	1	–

CURRENT ACCOUNTING CHANGES

Financial Instruments Disclosures

On Oct. 1, 2009, we adopted amendments to Section 3862, *Financial Instruments – Disclosures*, to converge with *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 implementation of this standard did not have an impact upon our consolidated financial statements as the disclosure requirements are already provided as part of our existing financial instrument disclosures.

Financial Instruments – Recognition and Measurement

On July 29, 2009, we retrospectively adopted, to Jan. 1, 2009, *Impairment of Financial Assets*, amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendments changed the categories into which debt instruments could be classified and the impairment requirements for certain financial assets. Consequential amendments to Section 3025, *Impaired Loans*, were made to incorporate these changes. The implementation of this standard did not have an impact upon our consolidated financial statements.

On July 1, 2009, we adopted *Embedded Derivatives on Reclassification of Financial Assets*, amending Section 3855, *Financial Instruments – Recognition and Measurement*. The amendment indicates that contracts with embedded derivatives cannot be reclassified out of the held for trading category if the embedded derivative cannot be fair valued. The implementation of this standard did not have an impact upon our consolidated financial statements.

Credit Risk

On Jan. 1, 2009, we 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. The implementation of this standard did not have a material impact upon our consolidated financial statements.

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 further defines that an internally developed intangible asset must demonstrate 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 in order to be able to capitalize associated costs. The implementation of this standard did not have an impact upon our consolidated financial statements.

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 an impact upon our consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Business Combinations and Non-Controlling Interests

In January 2009, the Accounting Standards Board of Canada ("AcSB") issued Section 1582, *Business Combinations*, Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-controlling Interests*, which will be adopted concurrently. Section 1582 and Section 1602 propose significant changes with respect to accounting for business combinations and to the accounting and presentation of non-controlling interests, respectively. Section 1601 is a replacement of Section 1600, *Consolidated Financial Statements*, and its implementation is not expected to have an impact upon our consolidated financial position or results of our operations. We are currently assessing the impact of adopting the above standards on our consolidated financial statements.

IFRS Convergence

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

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

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

Based on the work to date, our view is that while IFRS uses a conceptual framework similar to Canadian GAAP and has many similarities to Canadian GAAP, there are several significant differences in accounting policies that must be addressed. The majority of differences for us are expected to arise in respect to:

- Additional disclosure reconciling the changes in individual classes of property, plant, and equipment and accumulated amortization,
- Costs related to major inspection activities being recognized as part of the carrying value of property, plant, and equipment and depreciated over the period until the next major inspection,
- Allowing an entity to recognize as at Jan. 1, 2010, all experience and transitional gains and losses related to employee future benefits to retained earnings with subsequent experience gains and losses being recorded in other comprehensive income, and
- Certain long-term contracts being deemed finance leases resulting in the associated property, plant, and equipment being removed from the Consolidated Balance Sheets and replaced with a long-term receivable representing the present value of lease payments to be received over the life of the contract. Payments received under the contract are recorded in revenue and interest income, dependent upon the interest rate and duration of the contract.

As we prepare for 2010 dual reporting, we continue to evaluate the transitional options available under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* as well as the most appropriate long-term accounting policies available under IFRS.

In 2010, the International Accounting Standards Board ("IASB") is expected to issue new guidance on the accounting for joint ventures. Under the issued exposure draft, certain joint ventures cannot be proportionately consolidated and must instead be accounted for as an equity investment on the balance sheet with the associated net income or loss from these joint ventures being recorded as equity earnings on the statement of earnings.

At this time, it is not anticipated that any other material new standards or amendments relating to these projects will be effective on convergence in 2011. However, the progress and recommendations of other IASB projects for financial instruments, post-employment benefits, financial statement presentation, revenue recognition, and leases are being closely monitored to ensure that any potential adverse impacts to the convergence project can be minimized. As a result, the full impact of adopting IFRS on our financial position and future results cannot reasonably be determined at this time.

NON-GAAP MEASURES

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

Net Earnings Reconciliation

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

Year ended Dec. 31	2009	2008	2007
Revenues	**2770**	3,110	2,775
Fuel and purchased power	**(1,228)**	(1,493)	(1,231)
Gross margin	**1,542**	1,617	1,544
Operations, maintenance, and administration	**667**	637	577
Depreciation and amortization	**475**	428	406
Taxes, other than income taxes	**22**	19	20
Operating expenses	**1,164**	1,084	1,003
Operating income	**378**	533	541
Foreign exchange gain (loss)	**8**	(12)	3
Writedown of mining development costs	**(16)**	–	–
Net interest expense	**(144)**	(110)	(133)
Equity loss	**–**	(97)	(50)
Other income	**8**	5	16
Earnings before non-controlling interests and income taxes	**234**	319	377
Non-controlling interests	**38**	61	48
Earnings before income taxes	**196**	258	329
Income tax expense	**15**	23	20
Net earnings	**181**	235	309

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 calculated using the weighted average common shares outstanding during the year.

In calculating comparable earnings for 2009, we have excluded the writedown of mining development costs, the impact of a future tax rate change, and the settlement of an outstanding commercial issue that has been recorded in other income as this was related to our previously held Mexican equity investment.

In calculating comparable earnings for 2008, we have also excluded the writedown of our Mexican equity investment.

In calculating comparable earnings for 2008 and 2007, we have excluded the impact of future tax rate changes, recoveries related to tax positions, and the tax law change in Mexico as they do not relate to the earnings in the period in which they have been reported. We also excluded the gains recorded on the sale of assets at the previously operated Centralia coal mine in 2008 and 2007 as we do not normally dispose of large quantities of fixed assets.

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

Earnings on a comparable basis are reconciled to net earnings below:

Year ended Dec. 31	2009	2008	2007
Net earnings	**181**	235	309
Gain on sale of assets at Centralia, net of tax	–	(4)	(10)
Change in life of Centralia parts, net of tax	**1**	12	3
Writedown of mining development costs, net of tax	**10**	–	–
Settlement of commercial issue, net of tax	**(6)**	–	–
Tax rate change	**(5)**	–	(48)
Recovery related to tax positions	–	(15)	(18)
Writedown of Mexican equity investment, net of tax	–	62	–
Change in tax law in Mexico	–	–	28
Earnings on a comparable basis	**181**	290	264
Weighted average common shares outstanding in the year	**201**	199	202
Earnings on a comparable basis per share	**0.90**	1.46	1.31

Free Cash Flow (Deficiency)

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

Sustaining capital expenditures for the year ended Dec. 31, 2009, represents total additions to property, plant, and equipment per the Consolidated Statements of Cash Flows less $524 million ($510 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2008, we invested $541 million ($515 million net of joint venture contributions). In 2007, we invested $182 million in growth projects.

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

Year ended Dec. 31	2009	2008	2007
Cash flow from operating activities	**580**	1,038	847
Add (Deduct):			
Sustaining capital expenditures	**(380)**	(465)	(417)
Dividends on common shares	**(226)**	(212)	(205)
Distribution to subsidiaries' non-controlling interests	**(58)**	(98)	(87)
Non-recourse debt repayments[1]	**(25)**	(28)	(47)
Other income	**(8)**	–	–
Timing of contractualy scheduled payments	–	(116)	–
Cash flows from equity investments	–	2	(4)
Centralia closure costs	–	–	24
Free cash flow (deficiency)	**(117)**	121	111

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

We seek to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to our business.

Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA")

Presenting EBITDA from period to period provides management and investors with a proxy for the amount of cash generated from operating activities before net interest expense, non-controlling interests, income taxes, and working capital adjustments.

Year ended Dec. 31	2009	2008	2007
Operating income	**378**	533	541
Accretion	**24**	22	24
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**493**	451	415
EBITDA	**895**	1,006	980

1 To calculate EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows because this number takes into account depreciation related to mine assets, which is included in cost of sales per the Consolidated Statements of Earnings .

Comparable Return on Capital Employed

Comparable ROCE measures the efficiency and profitability of capital investments and is calculated by taking comparable earnings before net interest expense, non-controlling interests, and income taxes, and dividing by the average invested capital excluding AOCI. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods.

The calculation of comparable earnings before net interest expense, non-controlling interests, and income taxes is presented below:

Year ended Dec. 31	2009	2008	2007
Earnings before income taxes per the Consolidated Statements of Earnings	**196**	258	329
Net interest expense	**144**	110	133
Non-controlling interests	**38**	61	48
Change in life of Centralia parts, pre-tax	**2**	18	6
Writedown of mining development costs, pre-tax	**16**	–	–
Settlement of commercial issue, pre-tax	**(7)**	–	–
Writedown of Mexican equity investment, pre-tax	**–**	97	–
Gain on sale of assets at Centralia, pre-tax	**–**	(6)	(15)
Change in tax law in Mexico	**–**	–	28
Comparable earnings before net interest expense, non-controlling interests, and income taxes	**389**	538	529

SELECTED QUARTERLY INFORMATION

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Revenue	**756**	**585**	**666**	**763**
Net earnings (loss)	**42**	**(6)**	**66**	**79**
Basic and diluted earnings (loss) per common share	**0.21**	**(0.03)**	**0.34**	**0.37**
Comparable earnings (loss) per common share	**0.18**	**(0.03)**	**0.34**	**0.40**

	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Revenue	803	708	791	808
Net earnings	33	47	61	94
Basic and diluted earnings per common share	0.17	0.24	0.31	0.47
Comparable earnings per common share	0.50	0.25	0.32	0.40

Basic and diluted earnings (loss) per common share and comparable earnings (loss) per common share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per common share for the four quarters making up the calendar year may sometimes differ from the annual earnings per common share.

CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the *Securities Exchange Act of 1934* ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Management's evaluation of our internal control over financial reporting did not include an evaluation of the internal controls of Canadian Hydro, and management's conclusion regarding the effectiveness of our internal control over financial reporting does not extend to the internal controls of Canadian Hydro.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 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 MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward looking statements. All forward looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from those projected.

In particular, this MD&A contains forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and upgrades, and their attendant costs; expectations related to future earnings and cash flow from operating activities; expectations relating to the timing of the completion of the FEED study regarding CCS and the cost of the study; estimates of fuel supply and demand conditions and the costs of procuring fuel; our plans to invest in existing and new capacity, and the expected return on those investments; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; our plans to install mercury control equipment at our Alberta Thermal operations and our initiative to reduce nitrogen oxide and mercury emissions from our Centralia Plant; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; expectations relating to the renegotiation of certain of the collective bargaining agreements to which we are a party; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; expectations for the outcome of existing or potential legal claims; and expectations for the ability to access capital markets at reasonable terms.

Factors that may adversely impact our forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) our provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of this MD&A and under the heading "Risk Factors" in our 2009 Annual Information Form.

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

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, the Corporation has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures, and established policies provide reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board carries out its responsibility principally through its Audit and Risk Committee ("the Committee"). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management, internal auditors, and external auditors to discuss internal controls, auditing matters, and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by the shareholders.

STEPHEN G. SNYDER
President & Chief Executive Officer

BRIAN BURDEN
Chief Financial Officer

February 23, 2010

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's internal control over financial reporting (as defined in Rules 13a–15f and 15d–15f under the *United States Securities Exchange Act* of 1934).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for TransAlta.

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO framework is a suitable framework for its evaluation of TransAlta Corporation's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta Corporation's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta Corporation's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper overrides. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process, and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

TransAlta Corporation's consolidated financial statements include the accounts of the Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures via proportionate consolidation in accordance with Canadian GAAP. Management does not have the contractual ability to assess the internal controls of these joint ventures. Once the financial information is obtained from the joint ventures it falls within the scope of TransAlta Corporation's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of the joint ventures. The 2009 consolidated financial statements of TransAlta Corporation included $1,576 million and $849 million of total and net assets, respectively, as of Dec. 31, 2009, and $437 million and $79 million of revenues and net earnings, respectively, for the year then ended related to these joint ventures.

TransAlta Corporation's consolidated financial statements include the accounts of Canadian Hydro Developers, Inc. from the date of acquisition. Management's evaluation of the internal control over financial reporting did not include an evaluation of the internal controls of Canadian Hydro Developers, Inc. Management's conclusion regarding the effectiveness of the internal control over financial reporting does not extend to the internal controls of Canadian Hydro Developers, Inc. The 2009 consolidated financial statements of TransAlta Corporation included $1,534 million and $484 million of total and net assets, respectively, as of Dec. 31, 2009, and $29 million of revenues and nil of net earnings, respectively, for the year then ended related to Canadian Hydro Developers, Inc.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at Dec. 31, 2009, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta Corporation for the year ended Dec. 31, 2009, has also issued a report on internal control over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

STEPHEN G. SNYDER
President & Chief Executive Officer

BRIAN BURDEN
Chief Financial Officer

February 23, 2010

INDEPENDENT AUDITORS' REPORT ON INTERNAL CONTROLS UNDER STANDARDS OF THE PUBLIC COMPANY ACCOUNTING OVERSIGHT BOARD (UNITED STATES)

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the corporation's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the CE Generation, Sheerness, Wailuku, and Genesee 3 joint ventures, which are included in the 2009 consolidated financial statements of the Corporation and constituted $1,576 million and $849 million of total and net assets, respectively, as of December 31, 2009, and $437 million and $79 million of revenues and net earnings, respectively, for the year then ended. Management's assessment of and conclusion on the effectiveness of internal control over financial reporting also did not include the internal controls of Canadian Hydro Developers, Inc. which is included in the 2009 consolidated financial statements of the Corporation and constituted $1,534 million and $484 million of total and net assets, respectively, as of December 31, 2009, and $29 million of revenues and nil of net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the CE Generation, Sheerness, Wailuku, Genesee 3 joint ventures, and Canadian Hydro Developers, Inc.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial position of TransAlta Corporation as at December 31, 2009 and 2008 and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 23, 2010, expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2010

INDEPENDENT AUDITORS' REPORT ON FINANCIAL STATEMENTS

To the Shareholders of TransAlta Corporation

We have audited the consolidated balance sheets of TransAlta Corporation as at December 31, 2009 and 2008 and the consolidated statements of earnings and retained earnings, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2009. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Corporation as at December 31, 2009 and 2008 and the consolidated results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with Canadian generally accepted accounting principles.

As discussed in Note 2(C) to the consolidated financial statements, in 2007 the Corporation changed its method of accounting for comprehensive income, financial instruments, and hedges.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2010 expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2010

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	2009	2008	2007
Revenues	**2,770**	3,110	2,775
Fuel and purchased power	**(1,228)**	(1,493)	(1,231)
	1,542	1,617	1,544
Operations, maintenance, and administration	**667**	637	577
Depreciation and amortization	**475**	428	406
Taxes, other than income taxes	**22**	19	20
	1,164	1,084	1,003
	378	533	541
Foreign exchange gain (loss) *(Note 7)*	**8**	(12)	3
Writedown of mining development costs *(Note 3)*	**(16)**	–	–
Net interest expense *(Notes 7 and 17)*	**(144)**	(110)	(133)
Equity loss *(Note 24)*	**–**	(97)	(50)
Other income *(Note 4)*	**8**	5	16
Earnings before non-controlling interests and income taxes	**234**	319	377
Non-controlling interests *(Note 5)*	**38**	61	48
Earnings before income taxes	**196**	258	329
Income tax expense *(Note 6)*	**15**	23	20
Net earnings	**181**	235	309
Retained earnings			
Opening balance	**688**	763	710
Common share dividends	**(235)**	(215)	(202)
Shares cancelled under NCIB *(Notes 20 and 21)*	**–**	(95)	(54)
Closing balance	**634**	688	763
Weighted average number of common shares outstanding in the year	**201**	199	202
Net earnings per share, basic and diluted *(Note 20)*	**0.90**	1.18	1.53

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

Dec. 31 *(in millions of Canadian dollars)*	2009	2008
		(Restated, Note 2)
Cash and cash equivalents *(Notes 7 and 24)*	**82**	50
Accounts receivable *(Notes 7, 8, 24, and 28)*	**421**	505
Collateral paid *(Note 7)*	**27**	37
Prepaid expenses *(Note 24)*	**18**	6
Risk management assets *(Notes 7, 9, and 10)*	**144**	200
Future income tax assets *(Note 6)*	**17**	3
Income taxes receivable	**39**	61
Inventory *(Note 11)*	**90**	51
	838	913
Long-term receivable *(Note 12)*	**49**	14
Property, plant, and equipment *(Notes 13 and 24)*		
Cost	**11,721**	9,932
Accumulated depreciation	**(4,143)**	(3,898)
	7,578	6,034
Goodwill *(Notes 14, 24, and 29)*	**434**	142
Intangible assets *(Notes 15 and 24)*	**333**	213
Future income tax assets *(Note 6)*	**204**	248
Risk management assets *(Notes 7, 9, and 10)*	**224**	221
Other assets *(Notes 16 and 24)*	**102**	39
Total assets	**9,762**	7,824
Accounts payable and accrued liabilities *(Notes 7 and 24)*	**521**	658
Collateral received *(Note 7)*	**86**	24
Risk management liabilities *(Notes 7, 9, and 10)*	**45**	148
Income taxes payable	**10**	15
Future income tax liabilities *(Note 6)*	**57**	14
Dividends payable	**61**	52
Current portion of long-term debt–recourse *(Notes 7 and 17)*	**7**	211
Current portion of long-term debt–non-recourse *(Notes 7, 17, and 24)*	**24**	33
Current portion of asset retirement obligation *(Note 18)*	**32**	45
	843	1,200
Long-term debt–recourse *(Notes 7 and 17)*	**3,857**	2,332
Long-term debt–non-recourse *(Notes 7, 17, and 24)*	**554**	232
Asset retirement obligation *(Notes 18 and 24)*	**250**	252
Deferred credits and other long-term liabilities *(Note 19)*	**136**	131
Future income tax liabilities *(Notes 6 and 24)*	**637**	596
Risk management liabilities *(Notes 7, 9, 10, and 24)*	**78**	102
Non-controlling interests *(Note 5)*	**478**	469
Common shareholders' equity		
Common shares *(Notes 20 and 21)*	**2,169**	1,761
Retained earnings *(Note 21)*	**634**	688
Accumulated other comprehensive income *(Note 21)*	**126**	61
Total shareholders' equity	**2,929**	2,510
Total liabilities and shareholders' equity	**9,762**	7,824

Contingencies *(Notes 26 and 28)*
Commitments *(Notes 7 and 27)*
Subsequent events *(Note 33)*

On behalf of the Board:

Donna Kaufman

Donna Soble Kaufman
Director

William D. Anderson

William D. Anderson
Director

See accompanying notes.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended Dec. 31 *(in millions of Canadian dollars)*	2009	2008	2007
Net earnings	**181**	235	309
Other comprehensive income (loss)			
(Losses) gains on translating net assets of self-sustaining foreign operations	**(209)**	342	(196)
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax[1]	**140**	(295)	215
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**280**	198	(41)
Loss on sale of Mexico equity investment reclassified to the Consolidated Statements of Earnings, net of tax[3] *(Note 24)*	**–**	(8)	–
Reclassification of derivatives designated as cash flow hedges to the Consolidated Balance Sheets, net of tax[4]	**(11)**	8	1
Reclassification of derivatives designated as cash flow hedges to net earnings, net of tax[5]	**(135)**	61	18
Other comprehensive income (loss)	**65**	306	(3)
Comprehensive income	**246**	541	306

1 Net of income tax expense of 26 million for the year ended Dec. 31, 2009 (2008–61 million recovery, 2007–25 million expense).

2 Net of income tax expense of 120 million for the year ended Dec. 31, 2009 (2008–129 million expense, 2007–16 million recovery).

3 Net of income tax expense of 9 million for the year ended Dec. 31, 2008 (2007–nil).

4 Net of income tax recovery of 4 million for the year ended Dec. 31, 2009 (2008–nil, 2007–nil).

5 Net of income tax recovery of 69 million for the year ended Dec. 31, 2009 (2008–30 million expense, 2007–7 million expense)..

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended Dec. 31 *(in millions of Canadian dollars)*	2009	2008	2007
Operating activities			
Net earnings	**181**	235	309
Depreciation and amortization *(Note 29)*	**493**	451	415
Gain on sale of equipment *(Note 4)*	**–**	(5)	(16)
Non-controlling interests *(Note 5)*	**38**	61	48
Asset retirement obligation accretion *(Note 18)*	**24**	22	24
Asset retirement costs settled *(Note 18)*	**(35)**	(37)	(38)
Future income taxes *(Note 6)*	**21**	1	(34)
Unrealized loss from risk management activities	**2**	12	26
Unrealized foreign exchange gain	**(11)**	(5)	(3)
Writedown of mining development costs *(Note 3)*	**16**	–	–
Equity loss *(Note 24)*	**–**	97	50
Other non-cash items	**–**	(4)	–
	729	828	781
Change in non-cash operating working capital balances *(Note 22)*	**(149)**	210	66
Cash flow from operating activities	**580**	1,038	847
Investing activities			
Acquisition of Canadian Hydro Developers, Inc., net of cash acquired *(Note 24)*	**(766)**	–	–
Additions to property, plant, and equipment	**(904)**	(1,006)	(599)
Proceeds on sale of property, plant, and equipment	**7**	30	47
Proceeds on sale of minority interest in Kent Hills *(Note 4)*	**29**	–	–
Equity investment	**–**	–	(20)
Restricted cash	**–**	248	57
Long-term receivable *(Note 12)*	**(41)**	(8)	–
Realized (losses) gains on financial instruments	**(16)**	52	107
Loan to equity investment	**–**	(245)	–
Proceeds on sale of equity investment *(Note 24)*	**–**	332	–
Net increase in collateral received from counterparties	**87**	–	–
Net decrease in collateral paid to counterparties	**7**	–	–
Settlement of adjustments on sale of Mexican equity investment	**(7)**	–	–
Other	**6**	16	(2)
Cash flow used in investing activities	**(1,598)**	(581)	(410)
Financing activities			
Net increase (decrease) in credit facilities *(Note 17)*	**620**	(243)	289
Repayment of long-term debt *(Note 17)*	**(796)**	(308)	(252)
Issuance of long-term debt *(Note 17)*	**1,119**	502	30
Dividends paid on common shares	**(226)**	(212)	(205)
Redemption of preferred securities	**–**	–	(175)
Funds paid to repurchase common shares under NCIB *(Note 21)*	**–**	(130)	(75)
Net proceeds on issuance of common shares *(Note 20)*	**398**	15	20
Decrease in advances to TransAlta Power	**–**	–	6
Realized gains on financial instruments	**–**	12	–
Distributions paid to subsidiaries' non-controlling interests *(Note 5)*	**(58)**	(98)	(87)
Other	**(4)**	(5)	5
Cash flow from (used in) financing activities	**1,053**	(467)	(444)
Cash flow from (used in) operating, investing, and financing activities	**35**	(10)	(7)
Effect of translation on foreign currency cash	**(3)**	9	(8)
Increase (decrease) in cash and cash equivalents	**32**	(1)	(15)
Cash and cash equivalents, beginning of year	**50**	51	66
Cash and cash equivalents, end of year	**82**	50	51
Cash taxes paid	**43**	47	75
Cash interest paid	**149**	106	142

See accompanying notes.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Description of the Business

TransAlta Corporation ("TransAlta" or "the Corporation"), was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992 after TransAlta Utilities Corporation ("TAU") became a subsidiary. The Corporation has two reportable segments that are supported by a corporate group that provides finance, treasury, tax, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, internal audit, and other administrative support.

The two reportable segments of the Corporation are as follows:

I. Generation

The Generation segment owns coal, gas, wind, geothermal, biomass, and hydro plants in Canada, the United States ("U.S."), and Australia. It generates its revenues from the sale of electricity, steam, gas, and ancillary services.

II. Commercial Operations & Development ("COD")

The COD segment derives revenues from the wholesale trading of electricity and other energy-related commodities and derivatives not supported by TransAlta-owned generation assets. COD also utilizes contracts of various durations for the forward sales of electricity and purchases of natural gas and transmission capacity to effectively manage available generating capacity and fuel and transmission needs on behalf of Generation.

B. Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP").

The consolidated financial statements include the accounts of TransAlta, all subsidiaries, and the proportionate share of the accounts of joint ventures and jointly controlled corporations.

C. Use of Estimates

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, currency exchange rates, inflation levels and commodity prices, changes in economic conditions and legislative and regulatory changes *(Notes 7, 9, 10, 13, 14, 15, 17, 18, 26, 30, and 31).*

D. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power and from energy marketing and trading activities. Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for being available, energy payments for generation of electricity, availability payments or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each is recognized upon output, delivery, or satisfaction of specific targets, all as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each megawatt hour ("MWh") produced at market prices, and are recognized upon delivery.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts and futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting and are presented on a net basis in the Consolidated Statements of Earnings. The initial recognition of fair value and subsequent changes in fair value affect reported net earnings in the period the change occurs. The fair values of those instruments that remain open at the balance sheet date represent unrealized gains or losses and are presented on the Consolidated Balance Sheets as risk management assets or liabilities.

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

E. Foreign Currency Translation

The Corporation's functional currency is Canadian dollars while self-sustaining foreign operations' functional currencies are U.S. and Australian dollars.

The Corporation's self-sustaining foreign operations are translated using the current rate method. Translation gains and losses resulting from translating these foreign operations are included in Other Comprehensive Income ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income ("AOCI"). Foreign currency denominated monetary and non-monetary assets and liabilities of self-sustaining foreign operations are translated at exchange rates in effect on the balance sheet date.

Transactions denominated in a currency other than the functional currency are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

F. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives, and certain non-financial derivatives are recognized on the Consolidated Balance Sheets from the point when the Corporation becomes a party to the contract. Financial liabilities are removed from the consolidated financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability. All financial instruments are measured at fair value upon initial recognition except for certain non-financial derivative contracts that meet the Corporation's expected purchase, sale or usage requirements, commonly termed normal purchase / normal sale ("NPNS") contracts. Measurement in subsequent periods depends on whether the financial instrument has been classified as held for trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the underlying exposure that is being hedged.

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

Derivative instruments are recorded on the Consolidated Balance Sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. TransAlta recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired, or substantively modified after Jan. 1, 2003. Changes in the fair values of derivative instruments are recognized in net earnings with the exception of the effective portion of (i) derivatives designated as cash flow hedges or (ii) hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation, which are recognized in OCI. Derivatives used in trading activities are described in more detail in Note 1(D).

Certain financial instruments can be designated as held for trading (the fair value option) on initial recognition even if the financial instrument was not acquired or incurred principally for the purpose of selling or repurchasing it in the near term. An instrument that is classified as held for trading by way of this fair value option must have reliable fair values and satisfy one of the following criteria (i) when doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities, or recognizing gains and losses on them on a different basis or (ii) it belongs to a group of financial assets, financial liabilities or both that are managed and evaluated on a fair value basis in accordance with TransAlta's risk management strategy, and are reported to senior management personnel on that basis.

Transaction costs are expensed as incurred for financial instruments classified or designated as held for trading. For other financial instruments, transaction costs are capitalized on initial recognition. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost. Financial guarantees that meet the definition of a derivative are measured at fair value and are subsequently re-measured at fair value at each balance sheet date.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge, or a hedge of foreign currency exposure of a net investment in a self-sustaining foreign operation. In order to manage the ratio of floating rate versus fixed rate debt, the Corporation uses interest rate swaps as fair value or cash flow hedges. To hedge exposures to anticipated changes in interest rates for forecasted issuances of debt the Corporation uses interest rate swaps as cash flow hedges. For cash flow hedges, the Corporation primarily uses physical and financial swaps, forward contracts, futures contracts, and options to hedge its exposure to fluctuations in electricity and natural gas prices. The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from anticipated transactions and firm commitments denominated in foreign currencies. To hedge exposure to changes in the carrying value of net investments in foreign operations that are a result of changes in foreign exchange rates, the Corporation primarily uses cross-currency interest rate swaps, foreign currency forward contracts, and foreign denominated debt.

To be accounted for as a hedge, a derivative must be designated and documented as a hedge, and must be highly effective at inception and on an ongoing basis. The documentation prepared for the derivative at inception defines all relationships between hedging instruments and hedged items, as well as the Corporation's risk management objective and strategy for undertaking various hedge transactions. The process of hedge accounting includes linking derivatives to specific assets and liabilities on the Consolidated Balance Sheets or to specific firm commitments or anticipated transactions.

The Corporation also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. To be classified as effective, it is reasonable to expect that the Corporation will fulfill its contractual obligations without having to purchase commodities in the market and cash flow exposure does not exist. If the above hedge criteria are not met, the derivative is accounted for on the Consolidated Balance Sheets at fair value, with subsequent changes in fair value recorded in net earnings in the period of change. For those instruments that the Corporation does not seek or are ineligible for hedge accounting, changes in fair value are recorded in net earnings.

a. Fair Value Hedges

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

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. If hedge criteria are met, interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness of cash flow hedges is achieved if the derivatives' cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows is similar. When hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified from OCI immediately to net earnings when it is probable that the forecasted transaction will not occur within the specified time period.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, as described above, gains and losses on these derivatives are recognized in net earnings in the same period and financial statement caption as the hedged exposure. Up to the date of settlement, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from anticipated transactions and firm commitments denominated in foreign currencies. If the hedging criteria are met, changes in value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate.

c. Foreign Currency Exposure of a Net Investment in a Self-Sustaining Foreign Operation Hedges

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

The Corporation primarily uses cross-currency interest rate swaps, foreign currency forward contracts, and foreign denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in self-sustaining foreign operations as a result of changes in foreign exchange rates. Gains and losses on these instruments that qualify for hedge accounting are reported in OCI with fair values recorded in risk management assets or liabilities.

G. Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of three months or less.

H. Collateral Paid and Received

The terms and conditions of certain contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

I. Inventory

The majority of fuel and purchased power recorded on the Consolidated Statements of Earnings reflects the cost of inventory consumed in the generation of electricity. All inventory is carried at the lower of cost and net realizable value and cost is determined using the weighted average cost method.

The cost of internally produced coal inventory is determined using absorption costing which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower production as maintenance is performed. Due to the limited amount of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption.

The cost of natural gas inventory includes all applicable expenditures and charges incurred in bringing inventory to its existing condition and location.

J. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is stated at original cost at the time of construction, purchase, or acquisition. Original cost includes items such as materials, labour, interest, and other appropriately allocated costs. As costs are expended for new construction, these costs are capitalized as PP&E on the Consolidated Balance Sheets and are subject to depreciation upon commencement of commercial operations. The cost of routine maintenance and repairs, such as inspections and corrosion removal, and the replacement of minor parts, are charged to expense as incurred. Certain expenditures relating to the replacement of components incurred during major maintenance are capitalized and amortized over the estimated benefit period of such expenditures. A component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

The estimate of the useful life of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the PP&E is depreciated or amortized. These estimates are subject to revision in future periods based on new or additional information. Depreciation and amortization are calculated using straight-line and unit-of-production methods. Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserves.

TransAlta capitalizes interest on capital invested in projects under construction. Upon commencement of commercial operations, capitalized interest, as a portion of the total cost of the plant, is amortized over the estimated useful life of the plant.

On an annual basis, and when indicators of impairment exist, TransAlta determines whether the net carrying amount of PP&E is recoverable from future undiscounted cash flows. Factors that could indicate an impairment exists, include significant underperformance relative to historical or projected future operating results, significant changes in the manner or use of the assets, significant negative industry or economic trends, or a change in the strategy for the Corporation's overall business. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where TransAlta is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's businesses, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates possible impairment. If such an event has occurred, an estimate is made of future undiscounted cash flows from the PP&E. If the total of the undiscounted future cash flows, excluding financing charges with the exception of plants that have specifically dedicated debt, is less than the carrying amount of the PP&E, an asset impairment must be recognized in the consolidated financial statements. The amount of the impairment charge to be recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties, and is normally estimated by calculating the present value of expected future cash flows related to the asset.

K. Goodwill

Goodwill is the cost of an acquisition less the fair value of the related identifiable net assets of an acquired business. Goodwill is not subject to amortization, but instead is tested for impairment at least annually, or more frequently if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the reporting segment to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting segments to which the goodwill relates is compared to the carrying values of the reporting segments. The Corporation determined that the fair value of each reporting segment exceeded its carrying values as at Dec. 31, 2009 and 2008.

L. Intangible Assets

Intangible assets consist of power sale contracts, with rates higher than market rates at the date of acquisition, primarily acquired in the purchase of Canadian Hydro Developers, Inc. ("Canadian Hydro") *(Note 24)* and CE Generation LLC ("CE Gen"), a jointly controlled enterprise *(Note 32)*. Sale contracts are valued at cost and are amortized on a straight-line basis over the remaining applicable contract period, which ranges from one to 25 years.

M. Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are included in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the future costs are included in PP&E or investments. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to expense.

N. Income Taxes

The Corporation follows Canadian GAAP for non-regulated entities for all electricity generation operations and as a result, future income taxes have been recorded for all operations.

The Corporation uses the liability method of accounting for income taxes for its operations. Under the liability method, income taxes are recognized for the differences between financial statement carrying values and the respective income tax basis of assets and liabilities (temporary differences), and the carryforward of unused tax losses. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is included in net earnings in the period the change is substantively enacted. Future income tax assets are evaluated annually and if realization is not considered 'more likely than not', a valuation allowance is provided.

TransAlta's income tax positions are based on research and interpretations of the income tax laws and rulings in each of the jurisdictions in which the Corporation operates. The Corporation's operations are complex, and the computation and provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing and as such, further appeals and audits by taxation authorities may result. The outcome of some audits may change the tax liability of the Corporation. Management believes it has adequately provided for income taxes based on all information currently available.

O. Employee Future Benefits

The Corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets. The cost of pensions and other post-employment and post-retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. The defined benefit pension plans are based on an employee's final average earnings and years of service. The expected return on plan assets is based on expected future capital market returns. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. As the members of the Canadian Registered Plan are now almost all inactive, the past service costs from plan amendments and the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets are amortized over the Estimated Average Remaining Life ("EARL"). When the restructuring of a benefit plan gives rise to both a curtailment and settlement of obligations, the curtailment is accounted for prior to the settlement. Transition obligations and assets arising from the prospective adoption of new accounting standards are amortized over EARL. This method has not been applied to the Centralia plan as it did not qualify because the majority of its members are still active. The U.S. plan is amortized using Estimated Average Remaining Service Life ("EARSL").

In 2007, the past service costs and actuarial gains and losses on defined benefit plans had been amortized using EARSL *(Note 2)*.

P. Long-Term Debt

Transaction costs are recorded against the carrying value of long-term debt. The Corporation uses the effective interest method to amortize issuance costs and fees associated with long-term debt. A portion of the debt has been hedged using fixed to floating interest rate swaps and therefore the Corporation has included the fair value of these swaps with the value of the debt.

Q. Asset Retirement Obligation ("ARO")

The Corporation recognizes ARO in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The ARO liability is accrued over the estimated time period until settlement of the obligation and the asset is depreciated over the estimated useful life of the asset. Reclamation costs for mining assets are recognized on a unit-of-production basis.

TransAlta has recorded an ARO for all generating facilities for which it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not legally required to remove the structures. TransAlta has recognized legal obligations arising from government legislation, written agreements between entities, and case law. The asset retirement liabilities are recognized when the ARO is incurred. Asset retirement liabilities for coal mines are incurred over time, as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

For active mines, accretion expense is included in fuel and purchased power.

R. Stock-Based Compensation Plans

The Corporation has two types of stock-based compensation plans as described in Note 30. Under the fair value method for stock options, compensation expense is measured at the grant date at fair value and recognized over the service period.

Stock grants under the Performance Share Ownership Plan ("PSOP") are accrued in operations, maintenance, and administration ("OM&A") expense as earned to the balance sheet date, based upon the percentile ranking of the total shareholder return of the Corporation's common shares in comparison to the total shareholder returns of companies comprising the comparator group. Compensation expense under the phantom stock option plan is recognized in OM&A for the amount by which the quoted market price of TransAlta's shares exceed the option price, and adjusted for changes in each period for changes in the excess over the option price. If stock options or stock are repurchased from employees, the excess of the consideration paid over the carrying amount of the stock option or stock cancelled is charged to retained earnings.

S. Accounting for Emission Credits and Allowances

Purchased emission allowances are recorded on the Consolidated Balance Sheets at historical cost and are carried at the lower of weighted average cost and net realizable value. Allowances granted to TransAlta or internally generated are recorded at nil. TransAlta records an emission liability on the Consolidated Balance Sheets using the best estimate of the amount required to settle the Corporation's obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, these amounts are recognized as revenue in the period of recovery.

Proprietary trading of emissions allowances that meet the definition of a derivative are accounted for using the fair value method of accounting. Allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

T. Planned Maintenance

Planned maintenance is performed at regular intervals and the expenditures include both expense and capital portions. The planned major maintenance includes repairs and maintenance of existing components and the replacement of existing components. Repairs and maintenance of existing components are expensed in the period incurred. Costs of replacing existing components are capitalized in the period of maintenance activities and amortized on a straight-line basis over the life of the asset. Any remaining net book value of the component being replaced is expensed through depreciation. A component is a tangible portion of the asset that can be separately identified as an asset and depreciated over its own expected useful life, and is expected to provide a benefit of greater than one year.

U. Business Combinations

Acquisitions are recorded using the purchase method of accounting, in accordance with Handbook Section 1581, *Business Combinations*, with the results of operations included in these consolidated financial statements from the date of acquisition *(Note 24)*. The purchase price has been allocated to assets acquired and liabilities assumed at the date of acquisition. The amounts assigned to the net assets acquired have given rise to future income tax liabilities that have been recorded as part of the purchase price allocation. The excess of the purchase price over the fair values assigned to the identifiable net assets acquired has been recorded as goodwill.

2. ACCOUNTING CHANGES

A. Current Year Reclassifications

Certain of the comparative figures have been reclassified to conform with the current year's presentation. Such reclassification did not impact previously reported net earnings or retained earnings.

I. Classification of Pension Assets

During 2009, pension assets were classified on the Consolidated Balance Sheets as other assets. In 2008, $9 million was reclassified from deferred credits and other long-term liabilities to other assets in order to present comparable figures.

II. Classification of Collateral

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

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

III. Classification of Mining Development Costs

During 2009, mining development costs were classified on the Consolidated Balance Sheets as PP&E. In 2008, $13 million was reclassified from other assets to PP&E in order to present comparable figures.

IV. Classification of Debt

The Corporation's credit facilities extend for more than one year, and as a result the outstanding balance of the Corporation's credit facilities has been reclassified from short-term debt to recourse long-term debt on the Consolidated Balance Sheets. In 2008, $443 million was reclassified in order to present comparable figures.

B. Current Year Accounting Changes

I. Financial Instruments – Disclosures

On Oct. 1, 2009, the Corporation adopted amendments to Section 3862, *Financial Instruments – Disclosures*, to converge with *Improving Disclosures about Financial Instruments (Amendments to 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 implementation of this standard did not have an impact upon the consolidated financial statements as the disclosure requirements are already provided as part of the Corporation's existing financial instrument disclosures.

II. Financial Instruments–Recognition and Measurement

On July 29, 2009, the Corporation retrospectively adopted, to Jan. 1, 2009, *Impairment of Financial Assets,* amending Section 3855, *Financial Instruments–Recognition and Measurement.* The amendments changed the categories into which debt instruments could be classified and the impairment requirements for certain financial assets. Consequential amendments to Section 3025, *Impaired Loans,* were made to incorporate these changes. The implementation of this standard did not have an impact upon the consolidated financial statements.

On July 1, 2009, the Corporation adopted *Embedded Derivatives on Reclassification of Financial Assets,* amending Section 3855, *Financial Instruments–Recognition and Measurement.* The amendment indicates that contracts with embedded derivatives cannot be reclassified out of the held for trading category if the embedded derivative cannot be fair valued. The implementation of this standard did not have an impact upon the consolidated financial statements.

III. 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 9.

IV. 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 further defines that an internally developed intangible asset must demonstrate 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 in order to be able to capitalize associated costs. The implementation of this standard did not have an impact upon the consolidated financial statements.

V. 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 an impact upon the consolidated financial statements.

C. Prior Year Accounting Changes

I. Employee Future Benefits

During 2008, TransAlta assessed the accounting treatment for the amortization of the past service costs and actuarial gains and losses on defined benefit plans. In prior years, the past service costs and actuarial gains and losses on defined benefit plans had been amortized using EARSL, which was determined by the actuary to be seven years. As a result of the assessment, TransAlta amortized the past service costs and actuarial gains and losses on defined benefit plans under Canadian GAAP using EARL for plans whose members are almost all retired, which is determined by the actuary to be 17 years. As the members of the Canadian Registered Plan are now almost all inactive, starting in 2008 the past service costs from plan amendments and the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets will be amortized over EARL.

II. Financial Instruments

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

Section 3861 outlines disclosure requirements that are designed to enhance financial statement users' understanding of the significance of financial instruments to an entity's financial position, performance, and cash flows. The presentation requirements outlined in this section have been adopted in the Corporation's financial instruments presentation and related disclosure.

III. Comprehensive Income

Section 1530 introduces comprehensive income, which consists of net earnings and OCI. OCI represents changes in shareholders' equity during a period arising from transactions and changes in prices, markets, interest rates, and exchange rates and includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, net of hedging activities, and changes in the fair value of the effective portion of cash flow hedging instruments. TransAlta has included in the consolidated financial statements the Consolidated Statements of Comprehensive Income. The cumulative changes in OCI are included in AOCI, which is presented as a new category of shareholders' equity on the Consolidated Balance Sheets.

IV. Financial Instruments – Recognition and Measurement

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

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

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

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

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

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

As part of the implementation of Handbook Section 3855, TransAlta selected Jan. 1, 2003 as the transition date with respect to the assessment of embedded derivatives. TransAlta recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantively modified on or after the selected transition date.

V. Hedges

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

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

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

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

Prior to the adoption of Section 3865, gains and losses on physical and financial swaps, forward sales contracts, futures contracts and options used to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices related to output from the plants and designated as hedges were recognized in net earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives were not recorded on the Consolidated Balance Sheets. Foreign currency forward contracts used to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies where hedge criteria were met were not recognized on the Consolidated Balance Sheets. Interest rate swaps used to manage the impact of fluctuating interest rates on existing debt were not recognized on the Consolidated Balance Sheets if they met hedge criteria.

VI. Impact upon adoption of Sections 1530, 3855 and 3865

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

D. Future Accounting Changes

I. Business Combinations and Non-Controlling Interests

In January 2009, the Accounting Standards Board of Canada ("AcSB") issued Section 1582, *Business Combinations*, Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-controlling Interests* which will be adopted concurrently. Section 1582 and Section 1602 propose significant changes with respect to accounting for business combinations and to the accounting and presentation of non-controlling interests, respectively. Section 1601 is a replacement of Section 1600, *Consolidated Financial Statements*, and its implementation is not expected to have an impact upon the consolidated financial position or results of operations. The Corporation is currently assessing the impact of adopting the above standards on the consolidated financial statements.

II. International Financial Reporting Standards ("IFRS") Convergence

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. On May 8, 2009, the AcSB re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that will be addressed as part of the convergence project. In respect of PP&E, additional disclosures reconciling the changes in individual classes of PP&E and accumulated amortization will be required, and costs related to major inspection activities will be recognized as part of the carrying value of PP&E and depreciated over the period until the next major inspection. For employee future benefits, an entity may recognize as at Jan. 1, 2010, all experience and transitional gains and losses related to employee future benefits to retained earnings with subsequent experience gains and losses being recorded in other comprehensive income. Long-term contracts deemed to be finance leases results in the associated PP&E being removed from the Consolidated Balance Sheets and replaced with a long-term receivable representing the present value of lease payments to be received over the life of the contract. Payments received under the contract are recorded in revenue and interest income, dependent upon the interest rate and duration of the contract.

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

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

3. WRITEDOWN OF MINING DEVELOPMENT COSTS

In 2006, TransAlta ceased mining activities at the Centralia mine but continued to develop the option to mine the Westfield site, a coal reserve located adjacent to Centralia Thermal. With the successful modifications of the boilers at Centralia Thermal and longer-term contracts in place to supply coal, in 2009 the project to develop the Westfields site, has now been placed on hold indefinitely and the costs that have been capitalized were expensed.

4. OTHER INCOME

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

During 2008 and 2007, mining equipment with a net book value of $2 million and $31 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million and $47 million, respectively.

5. NON-CONTROLLING INTERESTS

A. Consolidated Statements of Earnings

Year ended Dec. 31	2009	2008	2007
Stanley Power's interest in TransAlta Cogeneration L.P. *(Note 32)*	**23**	32	29
25 per cent interest in Saranac Partnership not owned by CE Gen	**14**	29	19
Natural Forces' interest in Kent Hills *(Note 4)*	**1**	–	–
Total	**38**	61	48

B. Consolidated Balance Sheets

As at Dec. 31	2009	2008
Stanley Power's interest in TransAlta Cogeneration L.P.	**434**	449
25 per cent interest in Saranac Partnership not owned by CE Gen	**16**	20
Natural Forces' interest in Kent Hills	**28**	–
Total	**478**	469

The change in non-controlling interests is outlined below:

Balance, Dec. 31, 2008	469
Distributions paid	(58)
Non-controlling interests portion of net earnings	38
Proceeds on sale of minority interest in Kent Hills *(Note 4)*	29
As at Dec. 31, 2009	478

C. Consolidated Statements of Cash Flows

The allocation of the distributions paid by subsidiaries to non-controlling interests is as follows:

Year ended Dec. 31	2009	2008	2007
Stanley Power	**38**	59	65
Minority interests of Saranac Partnership	**18**	39	22
Natural Forces	**2**	–	–
Total	**58**	98	87

6. INCOME TAXES

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2009	2008	2007
Earnings before income taxes	**196**	258	329
Equity loss	**–**	(97)	(50)
Earnings before income taxes and equity loss	**196**	355	379
Statutory Canadian federal and provincial income tax rate (%)	**29**	30	32
Expected income tax expense	**57**	105	121
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(29)**	(24)	(36)
Resolution of uncertain tax positions	**–**	(15)	(18)
Tax recovery on sale of Mexican equity investment *(Note 24)*	**–**	(35)	–
Capital taxes	**1**	1	2
Effect of tax rate changes	**(6)**	–	(48)
Statutory and other rate differences	**(4)**	(7)	(1)
Other	**(4)**	(2)	–
Income tax expense	**15**	23	20
Effective tax rate (%)	**8**	6	5

II. Components of Income Tax Expense

Year ended Dec. 31	2009	2008	2007
Current tax (recovery) expense	**(6)**	22	54
Future income tax expense related to the origination and reversal of temporary differences	**27**	1	14
Future income tax (recovery) expense resulting from changes in tax rates or laws	**(6)**	–	(48)
Income tax expense	**15**	23	20

B. Consolidated Balance Sheets

Significant components of the Corporation's future income tax assets (liabilities) are as follows:

As at Dec. 31	2009	2008
Net operating and capital loss carryforwards	**297**	231
Future site restoration costs	**75**	71
Property, plant, and equipment	**(839)**	(736)
Risk management assets and liabilities	**(82)**	(52)
Employee future benefits and compensation plans	**19**	24
Allowance for doubtful accounts	**19**	22
Other deductible temporary differences	**38**	81
Net future income tax liability	**(473)**	(359)

7. 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 *(Note 1(F))*. The following table analyses the carrying amounts of the financial assets and liabilities by category:

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

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

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
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					
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]	–	–	–	2,543	2,543
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 Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined as follows:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I Energy Trading fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

Level II

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

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers in Level II. Level II fair values also include fair values determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

Level III

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

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally-developed fundamental price forecast is used in the valuation.

As a result of the acquisition of Canadian Hydro, TransAlta also has various contracts with terms that extend beyond five years *(Note 24)*. Valuation of these contracts must be extrapolated as the lengths of these contracts make reasonably alternate fundamental price forecasts unavailable.

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

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

As at Dec. 31, 2009	Fair value[1]				Total carrying value
	Level I	Level II	Level III[3]	Total	
Financial assets and liabilities measured at fair value					
Net risk management assets (liabilities)[2]	–	271	(26)	245	245
Financial assets and liabilities measured at other than fair value					
Long-term debt	–	4,499	–	4,499	4,442

As at Dec. 31, 2008	Fair value[1]				Total carrying value
	Level I	Level II	Level III	Total	
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	–	2,542	–	2,542	2,808

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, accounts receivable, collateral paid, accounts payable and accrued liabilities, and collateral received).*

2 *Includes Energy Trading and other risk management assets and liabilities on a net basis (Note 9).*

3 *Resulting primarily from the acquisition of Canadian Hydro (Note 24).*

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. In limited circumstances, an internally-developed fundamental price forecast is used when commodity transactions extend into periods for which market-observable prices are not available.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined at Dec. 31, 2009 is estimated to be +/- $24 million (2008–nil). This estimate is based on a +/- one standard deviation move from the mean where historical data is used in the valuation. Where an internally-developed fundamental price forecast is used, reasonably alternate fundamental price forecasts sourced from external consultants are included in the estimate. For contracts with terms that extend beyond five years, valuation must be extrapolated as the lengths of these contracts make reasonably alternate fundamental price forecasts unavailable.

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 net earnings for the year ended Dec. 31, 2009 was a $1 million gain (2008–$16 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 9.

C. Inception Gains and Losses

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

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

As at Dec. 31	2009	2008	2007
Unamortized gain at beginning of year	**2**	3	4
New transactions	**(1)**	1	4
Recognized in the Consolidated Statements of Earnings during the period:			
Amortization	**(2)**	(2)	(5)
Unamortized (loss) gain at end of year	**(1)**	2	3

D. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with expected NPNS contracts that are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

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

i. Commodity Price Risk – Proprietary Trading

The Corporation's COD segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

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

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

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

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2009 associated with the Corporation's proprietary trading activities was $3 million (2008–$6 million).

ii. Commodity Price Risk – Generation

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

In addition, certain electricity sale contracts do not qualify as NPNS contracts. These contracts are designated as all-in-one hedges and result in a net asset or liability position on the Consolidated Balance Sheets. Upon physical delivery of the commodity, TransAlta receives a gross settlement at the contracted price. Upon receipt of payment, the related net risk management asset or liability is eliminated. If an all-in-one hedge contract cannot be settled by physical delivery of the underlying commodity, it will be settled financially.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta based on the average monthly Alberta Power Pool prices. While the contracts do not create any obligation for the physical delivery of electricity to other parties, the Corporation believes it has sufficient electrical generation available to satisfy these contracts.

Changes in market prices associated with cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through OCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2009 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $45 million (2008–$86 million).

The Corporation's policy on asset-backed transactions is to seek NPNS contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2009 associated with the Corporation's commodity derivative instruments used in the generation business, but which are not designated as hedges, was nil (2008–nil).

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity revenues received from Power Purchase Arrangements ("PPAs"). Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI for the years ended Dec. 31, 2009, 2008, and 2007, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading and hedging interest rate derivatives outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is 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.

Year ended Dec. 31	2009		2008		2007	
	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
50 basis point change	**5**	**(10)**	2	–	4	–

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

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, and the U.S., and Australian dollars, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

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

The possible effect on net earnings and OCI for the years ended Dec, 31, 2009, 2008, and 2007, due to changes in the exchange rates associated with financial instruments outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is consistent with a +/- one standard deviation move from the mean.

Year ended Dec. 31	2009		2008		2007	
Currency	Net earnings decrease[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
U.S.	**4**	**2**	4	2	–	4
AUD	**1**	**–**	2	–	1	–
Euro	**–**	**–**	–	3	1	2
Total	**5**	**2**	6	5	2	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.
2 The foreign exchange impact related to financial instruments used as the hedging instruments in the net investment hedges have been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Generation PPAs as receivables are substantially all secured by letters of credit.

At Dec. 31, 2009, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at year-end.

The Corporation's maximum exposure to credit risk at Dec. 31, 2009, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading positions, net of any collateral held, at Dec. 31, 2009 was $63 million (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 Dec. 31, 2009:

Per cent (%)	Investment grade	Non-investment grade	Total
Accounts receivable	92	8	**100**
Risk management assets	100	–	**100**

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in Note 8.

At Dec. 31, 2009, the Corporation did not have any significant past due trade receivables.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used in proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong balance sheet and stable investment grade credit ratings.

Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts may require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

TransAlta manages liquidity risk by monitoring liquidity on trading positions, preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital, reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Exposure Management Committee, senior management, and Board of Directors, and maintaining investment grade credit ratings.

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

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Accounts payable and accrued liabilities	521	–	–	–	–	–	521
Collateral received	86	–	–	–	–	–	86
Debt[1]	29	251	1,090	659	231	2,203	4,463
Energy Trading risk management (assets) liabilities[2]	(112)	(103)	(76)	(12)	1	31	(271)
Other risk management liabilities (assets)[2]	15	(7)	–	–	–	18	26
Interest on long-term debt	224	203	183	170	142	600	1,522
Total	**763**	**344**	**1,197**	**817**	**374**	**2,852**	**6,347**

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

2 Net risk management assets and liabilities (Note 9).

E. Financial Instruments Provided as Collateral

At Dec. 31, 2009, $45 million (2008–$63 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Gen have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

At Dec. 31, 2009, the Corporation provided $27 million (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.

F. Financial Assets Held as Collateral

At Dec. 31, 2009, the Corporation received $86 million (2008–$24 million) in cash as collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

G. Gains and Losses on Financial Instruments

The Corporation's COD segment utilizes a variety of derivatives in its proprietary trading activities, including certain commodity hedging activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the year ended Dec. 31, 2009, the COD segment recognized a net unrealized loss of $6 million (2008–$2 million net unrealized loss, 2007–$3 million net unrealized loss).

The Corporation's Generation segment utilizes a variety of derivatives in its operations, including certain commodity hedges that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the year ended Dec. 31, 2009, the Generation segment recognized a net unrealized gain of $3 million (2008–$12 million net unrealized loss, 2007–$30 million net unrealized loss).

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 its interest-bearing financial liabilities, primarily long-term debt. Interest expense is calculated using the effective interest method *(Note 17)*. 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 foreign exchange 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 (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 a portion of the settlement cost of certain employee compensation and deferred share unit programs. The total return swap is cash settled every quarter.

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

Year ended Dec. 31	2009	2008	2007
Foreign exchange derivatives (losses) gains	**(1)**	11	4
Interest rate derivatives losses	–	–	2
Other derivatives gains	–	1	–

8. ACCOUNTS RECEIVABLE

As at Dec. 31	2009	2008
Gross accounts receivable	**470**	562
Allowance for doubtful accounts *(Note 28)*	**(49)**	(57)
Net accounts receivable	**421**	505

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2008	57
Change in foreign exchange rates	(8)
Balance, Dec. 31, 2009	**49**

9. RISK MANAGEMENT ASSETS AND LIABILITIES

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

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

As at Dec. 31	2009			2008		
Balance Sheet–Totals	Energy Trading	Other	Total	Energy Trading	Other	Total
Risk management assets						
Current	**144**	**–**	**144**	176	24	200
Long-term	**207**	**17**	**224**	187	34	221
Risk management liabilities						
Current	**30**	**15**	**45**	142	6	148
Long-term	**50**	**28**	**78**	57	45	102
Net risk management assets (liabilities)	**271**	**(26)**	**245**	164	7	171

Energy Trading

The values of risk management assets and liabilities for Energy Trading are included on the Consolidated Balance Sheets as follows:

As at Dec. 31	2009			2008
Balance Sheet–Energy Trading	Hedges	Non-hedges	Total	Total
Risk management assets				
Current	**130**	**14**	**144**	176
Long-term	**202**	**5**	**207**	187
Risk management liabilities				
Current	**15**	**15**	**30**	142
Long-term	**47**	**3**	**50**	57
Net risk management assets	**270**	**1**	**271**	164

The following table illustrates the disclosure on the movements in the fair value of the Corporation's Energy Trading net risk management assets and liabilities separately by source of valuation during the year ended Dec. 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:									
Acquisition of Canadian Hydro *(Note 24)*	–	–	(31)	–	–	–	–	–	(31)
Commodity price changes	–	147	–	–	(2)	–	–	145	–
New contracts entered	–	37	(1)	–	–	1	–	37	–
Contracts settled	–	(20)	–	(1)	2	–	(1)	(18)	–
Change in foreign exchange rates	–	(25)	–	–	–	–	–	(25)	–
Transfers in/out of Level III	–	(5)	5	–	–	–	–	(5)	5
Net risk management assets (liabilities) at Dec. 31, 2009	**–**	**297**	**(27)**	**–**	**–**	**1**	**–**	**297**	**(26)**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			4			–			4
Unrealized gain(loss) included in earnings before income taxes relating to those net assets held at Dec. 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 both the COD and the Generation business segments.

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

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	110	99	76	13	(1)	–	297
	Level III	3	3	(1)	(1)	–	(31)	(27)
Non-hedges	Level I	–	–	–	–	–	–	–
	Level II	(2)	1	1	–	–	–	–
	Level III	1	–	–	–	–	–	1
Total	Level I	–	–	–	–	–	–	–
	Level II	108	100	77	13	(1)	–	297
	Level III	4	3	(1)	(1)	–	(31)	(26)
Total net assets (liabilities)		**112**	**103**	**76**	**12**	**(1)**	**(31)**	**271**

The Corporation's outstanding Energy Trading derivative financial instruments at Dec. 31, 2009, were as follows:

Units (000s)	Electricity (MWh)	Natural gas (GJ)	Transmission (MWh)	Oil (gallons)
Derivative financial instruments designated as hedges				
Notional Amounts				
Purchases	–	360	–	25,074
Sales	175,756	2,163	–	–
Derivative financial instruments held for trading (non-hedges)				
Notional Amounts				
Purchases	14,844	309,764	4,852	–
Sales	14,107	323,793	–	–

Other Risk Management Assets and Liabilities

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

As at Dec. 31	2009			2008
Balance Sheet–Other	Hedges	Non-hedges	Total	Total
Risk management assets				
Current	**–**	**–**	**–**	24
Long-term	**17**	**–**	**17**	34
Risk management liabilities				
Current	**13**	**2**	**15**	6
Long-term	**28**	**–**	**28**	45
Net risk management (liabilities) assets	**(24)**	**(2)**	**(26)**	7

The following table illustrates the disclosure on the movements in the fair value of the Corporation's other net risk management assets and liabilities separately by source of valuation during the year ended Dec. 31, 2009:

	Hedges	Non-hedges	Total
Net risk management assets (liabilities) at Dec. 31, 2008	8	(1)	7
Changes in net asset value attributable to:			
Market price changes	(20)	–	(20)
New contracts entered	(38)	(2)	(40)
Contracts settled	26	1	27
Net risk management liabilities at Dec. 31, 2009	**(24)**	**(2)**	**(26)**

Changes in non-Energy Trading risk management assets and liabilities for hedge positions are reflected within net earnings when such transactions have settled during the period or ineffectiveness exists in the hedging relationship. So 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 self-sustaining foreign operations.

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

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	(13)	7	–	–	–	(18)	(24)
Non-hedges	(2)	–	–	–	–	–	(2)
Total net (liabilities) assets	**(15)**	**7**	**–**	**–**	**–**	**(18)**	**(26)**

Additional information related to other risk management assets and liabilities designated as hedges and non-hedges 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 (2008 – U.S.$1,100 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 (purchase) contracts as shown below:

a. Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	AUD34	**(2)**	**2010**	AUD34	2	2009

b. Foreign Currency Contracts

Outstanding foreign currency forward sales (purchase) contracts are as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	AUD120	**(2)**	**2010**	AUD108	(1)	2009
	U.S.182	**(1)**	**2010**	U.S.(107)	(1)	2009

II. Hedges of Future Foreign Currency Obligations

a. Foreign Exchange Forward Contract

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:

As at Dec. 31	2009				2008			
	Amount sold	Amount purchased	Fair value liability	Maturity	Amount sold	Amount purchased	Fair value asset	Maturity
	91	**U.S.78**	**(8)**	**2010**	51	U.S.48	8	2009–2010
	U.S.14	**15**	**–**	**2010**	–	–	–	–
	AUD4	**U.S.3**	**–**	**2010**	–	–	–	–
	–	**–**	**–**	**–**	84	EUR57	13	2009

b. Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	U.S.(500)	**(16)**	**2015**	–	–	–

III. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 5.75 per cent to 6.65 per cent, to floating rate debt through interest rate swaps as shown below:

As at Dec. 31	2009			2008		
	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value asset	Maturity
	100	**7**	**2011**	100	12	2011
	U.S.50	**(1)**	**2013**	–	–	–
	U.S.150	**7**	**2018**	U.S.100	21	2018

Including the interest rate swaps above, 31 per cent of the Corporation's debt is subject to floating interest rates as at Dec. 31, 2009 (2008–24 per cent).

The Corporation also has an outstanding forward start interest rate swap that converts floating rate debt into fixed rate debt. The commencement date for this swap is March 5, 2010, with fixed rates ranging from 3.5 per cent to 4.6 per cent, as shown below:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	U.S.300	**(8)**	**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 foreign exchange and interest rates. The (liability) asset resulting from an outstanding cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	AUD13	**(2)**	**2010**	AUD41	1	2009

II. Foreign Currency Contracts

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

Outstanding notional amounts and fair values with these foreign currency forward sales (purchases) are as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	U.S.13	**–**	**2010**	U.S.90	(2)	2009

III. Total Return Swaps

The Corporation also has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been pursued. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter *(Note 7)*.

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 Dec. 31, 2009 the Corporation had posted collateral of $37 million in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at Dec. 31, 2009, the Corporation would be required to post an additional $29 million of collateral to its counterparties.

10. HEDGING ACTIVITIES

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

A. 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 in 2009, 2008, or 2007.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings:

Year ended Dec. 31		2009	2008	2007
Instruments in fair value hedging relationships	**Location of gain (loss) on the Consolidated Statements of Earnings**			
Interest rate contracts	Net interest expense	**20**	(26)	(34)
Long-term debt	Net interest expense	**(20)**	26	34
Net earnings impact		**–**	–	–

B. 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 year ended Dec. 31, 2009, a pre-tax unrealized gain of $400 million (2008–gain of $327 million, 2007–loss of $57 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $204 million (2008–$91 million, 2007–$25 million) related to amounts previously related to OCI was reclassified to net earnings. For the year ended Dec. 31, 2009, a realized loss of $2 million (2008–nil, 2007–nil), was recognized in net earnings for ineffectiveness.

Over the next 12 months, the Corporation estimates that $77 million (2008–$17 million after-tax losses) of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. In addition, it is the Corporation's intent to settle a substantial portion of the cash flow hedges by physical delivery of the underlying commodity, resulting in gross settlement at the contract price. These contracts are designated as all-in-one hedges and are required to be accounted for as cash flow hedges.

The following tables summarize the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets:

Year ended Dec. 31, 2009

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of gain (loss) reclassified from OCI**	**Pre-tax gain (loss) reclassified from OCI**	**Location of loss recognized in earnings**	**Pre-tax loss recognized in earnings**
Interest rate	**37**	Net interest expense	**1**	Net interest expense	**2**
Foreign exchange	**(31)**	Foreign exchange	**–**		
		Property, plant, and equipment	**(15)**		
Commodity	**394**	Revenue	**(205)**		
OCI impact	**400**	**OCI impact**	**(219)**	**Earnings impact**	**2**

Year ended Dec. 31, 2008

	Effective portion		
Derivatives in cash flow hedging relationships	**Pre-tax (loss) gain recognized in OCI**	**Location of gain reclassified from OCI**	**Pre-tax gain reclassified from OCI**
Interest rate	(56)	Net interest expense	–
Foreign exchange	31	Foreign exchange	–
		Property, plant, and equipment	8
Commodity	352	Revenue	91
OCI impact	327	OCI impact	99

Year ended Dec. 31, 2007

	Effective portion		
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (loss) gain reclassified from OCI**	**Pre-tax (loss) gain reclassified from OCI**
Interest rate	9	Net interest expense	(5)
Foreign exchange	(10)	Foreign exchange	–
		Property, plant, and equipment	1
Commodity	(56)	Revenue	30
OCI impact	(57)	OCI impact	26

C. Net Investment Hedges

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

For the year ended Dec. 31, 2009, a net after-tax loss of $69 million (2008 – gain of $47 million, 2007 – gain of $19 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income:

Derivatives in net investment hedging relationships	Pre-tax (losses) gains recognized in OCI for the year ended Dec. 31, 2009	Pre-tax losses recognized in OCI for the year ended Dec. 31, 2008	Pre-tax (losses) gains recognized in OCI for the year ended Dec. 31, 2007
Foreign exchange	**(64)**	(37)	(2)
Cross currency	**(3)**	(62)	152
Long-term debt	**233**	(257)	90
OCI impact	**166**	(356)	240

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 Dec. 31	2009					2008
	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated as a Hedge	Total	Total
Financial derivative assets						
Energy Trading	–	**332**	–	**19**	**351**	363
Non-Energy Trading	**14**	**3**	–	–	**17**	58
Total	**14**	**335**	–	**19**	**368**	421
Financial derivative liabilities						
Energy Trading	–	**62**	–	**18**	**80**	199
Non-Energy Trading	**1**	**35**	**5**	**2**	**43**	51
Total	**1**	**97**	**5**	**20**	**123**	250

Additional information on derivative instruments has been presented on a net basis in Note 9.

11. INVENTORY

Inventory includes coal, natural gas, and emission credits which are valued at the lower of cost and net realizable value.

As at Dec. 31	2009	2008
Coal	**86**	45
Natural gas	**4**	5
Purchased emission credits	–	1
Total	**90**	51

The increase in coal inventory in 2009 compared to 2008 is primarily due to lower production at the Centralia and Alberta Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2008	51
Net additions	44
Change in foreign exchange rates	(5)
Balance, Dec. 31, 2009	**90**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2009 and 2008, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

12. LONG-TERM RECEIVABLE

In 2008, the Corporation received a notice of reassessment from the federal taxation authority in Canada related to the disposal of the Transmission Business in the 2002 taxation year. As a result of the reassessment, the Corporation was required by law to pay approximately $49 million in taxes plus interest and penalties notwithstanding the Corporation's ability to challenge this reassessment. The Corporation funded a portion of this amount in 2008 by transferring $8 million from its tax prepayment account. Additional cash payments and a loss carryback were applied in 2009 to fund the remaining balance. The Corporation is in the process of challenging this reassessment. Since it is anticipated that the dispute will not be resolved within one year, these prepayments have been recorded as a long-term receivable.

13. PROPERTY, PLANT, AND EQUIPMENT

As at Dec. 31		2009			2008		
	Depreciable lives	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation equipment	**3–50**	**4,709**	**2,267**	**2,442**	4,835	1,993	2,842
Mining property & equipment	**4–50**	**795**	**415**	**380**	776	352	424
Gas generation	**2–30**	**2,135**	**883**	**1,252**	2,244	1,030	1,214
Geothermal generation	**10–20**	**333**	**101**	**232**	386	87	299
Hydro generation	**3–60**	**611**	**172**	**439**	399	226	173
Wind generation	**30**	**1,556**	**125**	**1,431**	375	39	336
Biomass	**15–30**	**25**	**1**	**24**	–	–	–
Capital spares and other	**2–15**	**270**	**65**	**205**	228	68	160
Assets under construction	**–**	**1,038**	**–**	**1,038**	443	–	443
Coal rights[1]	**–**	**133**	**86**	**47**	134	83	51
Land	**–**	**68**	**–**	**68**	63	–	63
Transmission systems	**15–50**	**48**	**28**	**20**	49	20	29
Total		**11,721**	**4,143**	**7,578**	9,932	3,898	6,034

1 Coal rights are amortized on a unit-of-production basis, based on the estimated mine reserve.

The Corporation capitalized $36 million of interest to PP&E in 2008 (2008–$21 million, 2007–$6 million).

The change in PP&E is outlined below:

	Cost	Accumulated depreciation and amortization	Net book value
Balance, Dec. 31, 2008	9,932	3,898	6,034
Acquisition of Canadian Hydro *(Note 24)*	1,291	–	1,291
Additions	904	–	904
Disposals	(10)	(6)	(4)
Depreciation	–	463	(463)
Change in foreign exchange rates	(273)	(94)	(179)
Retirement of assets	(132)	(118)	(14)
Transfers	9	–	9
Balance, Dec. 31, 2009	**11,721**	**4,143**	**7,578**

14. GOODWILL

The change in goodwill is outlined below:

Balance, Dec. 31, 2008	142
Acquisition of Canadian Hydro *(Note 24)*	304
Change in foreign exchange rates	(12)
Balance, Dec. 31, 2009	**434**

A portion of goodwill in Generation is related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars *(Note 29)*. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

15. INTANGIBLE ASSETS

The change in intangible assets is outlined below:

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2008	499	286	213
Acquisition of Canadian Hydro *(Note 24)*	176	–	176
Change in foreign exchange rates	(68)	(43)	(25)
Amortization	–	31	(31)
Balance, Dec. 31, 2009	**607**	**274**	**333**

A portion of intangible assets are related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

16. OTHER ASSETS

As at Dec. 31	2009	2008
Deferred license fees	**22**	21
Accrued pension benefit asset *(Note 31)*	**18**	9
Project development costs	**45**	4
Keephills 3 transmission deposit	**8**	–
Other	**9**	5
Total other assets	**102**	39

Deferred license fees consist primarily of a license to lease the land on which certain generating assets are located, and are being amortized on a straight-line basis over the useful life of the generating assets to which the license relates.

The Keephills 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit for Keephills 3. The full amount of the deposit is anticipated to be reimbursed over the next 10 years, as long as certain performance criteria are met.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects.

17. LONG-TERM DEBT AND NET INTEREST EXPENSE

A. Amounts Outstanding

As at Dec. 31	2009			2008		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**1,063**	**1,063**	**1.0%**	443	443	2.8%
Debentures, due 2011 to 2030	**1,055**	**1,076**	**6.7%**	682	681	6.8%
Senior notes[3]	**1,687**	**1,684**	**5.9%**	1,352	1,344	6.3%
Non-recourse	**578**	**581**	**6.3%**	265	265	7.4%
Other	**59**	**59**	**6.7%**	66	66	6.7%
	4,442	**4,463**		2,808	2,799	
Less: current portion	**(31)**	**(31)**		(244)	(244)	
Total long-term debt	**4,411**	**4,432**		2,564	2,555	

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

2 Composed of Bankers' Acceptances and other commercial borrowings under long-term committed credit facilities.

3 2009–U.S.$1,600 million, 2008–U.S.$1,100 million.

A portion of the fixed rate components of debentures and senior notes have been hedged using fixed to floating interest rate swaps and therefore the Corporation has included the fair value of these swaps with the value of the debt. Non-recourse debt is not hedged and therefore recorded at cost.

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's businesses. The facility is a five-year revolver which was last renewed in May 2007 and matures in 2012. The U.S.$300 million committed facility is a five-year facility that matures in 2013. Interest rates on the credit facilities vary depending on the option selected; Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities all of which mature in 2011.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent. The Corporation has converted $100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of interest rate swaps (Note 9). These interest rate swaps mature in 2011. During 2009, the Corporation issued a total of $600 million in debentures; $200 million was issued in May 2009 at a fixed interest rate of 6.45 per cent, maturing in 2014 and $400 million was issued in November 2009 at a fixed rate of 6.4 per cent, maturing in 2019.

Senior Notes U.S.$300 million of the senior notes bear an interest rate of 5.75 per cent and mature in 2013 and another U.S.$300 million bear an interest rate of 6.75 per cent and mature in 2012. U.S.$500 million bear interest at 6.65 per cent and mature in 2018, and the remaining U.S.$500 million of the senior notes were issued in November 2009 and bear an interest rate of 4.75 per cent and mature in 2015. In addition, the Corporation converted U.S.$50 million and U.S.$150 million fixed interest rate debt with rates of 5.8 per cent and 6.7 per cent, respectively, to floating rates through the use of interest rate swaps (Note 9). These interest rate swaps mature in 2013 and 2018, respectively. A total of U.S.$1,100 million of the senior notes has been designated as a hedge of the Corporation's net investment of U.S. self-sustaining foreign operations.

Non-Recourse Debt consists of project financing debt, debt securities and senior secured bonds of CE Gen, debt related to the Wailuku River Hydroelectric L.P ("Wailuku") acquisition, and debentures issued by Canadian Hydro. The CE Gen related assets have been pledged as security for the project financing debt. The CE Gen debt has maturity dates ranging from 2010 to 2018 and interest rates ranging from 7.5 per cent to 8.3 per cent. This debt is recorded at cost; the fair value as at Dec. 31, 2009 was U.S.$184 million (2008 – U.S.$208 million). Wailuku debt at Dec. 31, 2009 has a cost of U.S.$8 million (2008–U.S.$9 million) and bears interest at a floating rate currently of 1.2 per cent. The Canadian Hydro debt has maturity dates ranging from 2010 to 2018 and interest rates ranging from 5.3 per cent to 10.9 per cent and includes debt with a cost of $355 million and U.S.$20 million. This debt is recorded at cost; the fair value as at Dec. 31, 2009 was $376 million.

Other consist of notes payable for the Windsor Plant which bears interest at fixed rates and are recourse to the Corporation through a standby letter of credit. These mature in November 2014. Also included is a commercial loan obligation which bears an interest rate of 5.9 per cent and will mature in 2023. This is an unsecured loan and requires annual payments of interest and principal.

B. Principal Repayments

2010	29
2011	251
2012	1,090
2013	659
2014	231
2015 and thereafter	2,203
Total[1]	**4,463**

1 Excludes impact of derivatives and includes credit facilities that are currently scheduled to mature in 2012 and 2013.

C. Interest Expense

Year ended Dec. 31	2009	2008	2007
Interest on long-term debt	**183**	177	171
Interest income	**(6)**	(46)	(32)
Capitalized interest	**(36)**	(21)	(6)
Other	**3**	–	–
Net interest expense	**144**	110	133

The Corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2009 relates primarily to Keephills 3 and associated mine capital, Blue Trail, and Summerview II. In 2008 the capitalized interest related to the Corporation's investment in Keephills 3 and associated mine capital, Kent Hills, Summerview, and Blue Trail.

In 2008, an appeal was resolved pertaining to the timing of revenue recognition and deductions on previous years' tax returns based on applicable income tax laws. Consequently, a $30 million interest refund from taxation authorities was recorded as interest income.

D. Guarantees

I. Letters of Credit

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Balance Sheets. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Dec. 31, 2009 totalled $334 million (2008–$430 million) with nil (2008–nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.1 billion of committed credit facilities of which $0.7 billion is not drawn and is available as of Dec. 31, 2009, subject to customary borrowing conditions.

18. ASSET RETIREMENT OBLIGATION

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

Balance, Dec. 31, 2008	297
Liabilities incurred in period	3
Liabilities settled in period	(35)
Accretion expense	24
Revisions in estimated cash flows	10
Acquisition of Canadian Hydro *(Note 24)*	3
Change in foreign exchange rates	(20)
	282
Less: current portion	(32)
Balance, Dec. 31, 2009	**250**

The Corporation has a right to recover a portion of future asset retirement costs.

TransAlta estimates that the undiscounted amount of cash flow required to settle the asset retirement obligation is approximately $0.8 billion which will be incurred between 2010 and 2072. The majority of the costs will be incurred between 2020 and 2030. An average discount rate of eight per cent and an inflation rate of two per cent were used to calculate the carrying value of the asset retirement obligation. At Dec. 31, 2009, the Corporation had provided a surety bond in the amount of U.S.$192 million (2008–U.S.$192 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2009, the Corporation had provided letters of credit in the amount of $67 million (2008–$57 million) in support of future retirement obligations at the Alberta mines.

19. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

As at Dec. 31	2009	2008
Deferred coal revenues *(Note 25)*	**51**	31
Sale of emission credits	**1**	7
Power purchase arrangement in limited partnership	**21**	23
Accrued benefit liability *(Note 31)*	**49**	49
Other	**14**	21
Total deferred credits and other long-term liabilities	**136**	131

The power purchase arrangement in the limited partnership represents the fair value adjustments for the Sheerness Generating Station to deliver power at less than the prevailing market price at the time of the acquisition of the plant by TransAlta Cogeneration, L.P. ("TA Cogen"). The power purchase arrangement is amortized on a straight-line basis over the life of the contract.

20. COMMON SHARES

A. Issued and Outstanding

The Corporation is authorized to issue an unlimited number of voting common shares without nominal or par value.

Year ended Dec. 31	2009		2008	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**197.6**	**1,761**	200.9	1,781
Issued under stock option plans	–	–	0.4	8
Issued under Performance Share Ownership Plan	**0.2**	**6**	0.2	7
Shares purchased under NCIB *(Note 21)*	–	–	(3.9)	(35)
Issued, net of tax[1]	**20.6**	**402**	–	–
Issued and outstanding, end of year	**218.4**	**2,169**	197.6	1,761

1 *Net of issuance costs of $16 million and tax expense of $4 million.*

At Dec. 31, 2009 the Corporation had 1.5 million outstanding employee stock options (2008–1.7 million). For the year ended Dec. 31, 2009, no options were exercised.

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. The plan is put before the shareholders every three years for approval, and was last approved on April 26, 2007.

When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a Permitted Bid, where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

C. Dividend Reinvestment and Share Purchase ("DRASP") Plan

Under the terms of the DRASP plan, participants are able to purchase additional common shares by reinvesting dividends. Shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the Toronto Stock Exchange on the investment dates.

D. Earnings Per Share ("EPS")

Year ended Dec. 31	2009	2008	2007
Net earnings	**181**	235	309
Basic and diluted weighted average number of common shares outstanding	**201**	199	202
Earnings per share			
Basic and diluted	**0.90**	1.18	1.53

The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding *(Note 30)*.

21. SHAREHOLDERS' EQUITY

	Common shares	Retained earnings	Accumulated other comprehensive income/(loss)	Total shareholders' equity
Balance, Dec. 31, 2008	1,761	688	61	2,510
Net earnings	–	181	–	181
Common shares issued	408	–	–	408
Dividends declared		(235)		(235)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	–	–	(69)	(69)
Gains on derivatives designated as cash flow hedges, net of tax	–	–	280	280
Derivatives designated as cash flow hedges in prior periods transferred to the Consolidated Balance Sheets and net earnings in the current period, net of tax	–	–	(146)	(146)
Balance, Dec. 31, 2009	**2,169**	**634**	**126**	**2,929**

Components of AOCI

As at Dec. 31	2009	2008
Cumulative unrealized (losses) gains on translating self-sustaining foreign operations, net of hedges and of tax	**(63)**	6
Cumulative unrealized gains on cash flow hedges, net of tax	**189**	55
Total accumulated other comprehensive income	**126**	61

Normal Course Issuer Bid ("NCIB") program

On May 6, 2009, TransAlta announced plans to renew the NCIB program until May 6, 2010. The Corporation received the approval to purchase, for cancellation, up to 9.9 million of its common shares representing five per cent of the 198 million common shares issued and outstanding as at April 30, 2009. 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.

No purchases were made under the NCIB program in 2009.

For the year ended Dec. 31, 2008, TransAlta purchased 3,886,400 shares at an average price of $33.46 per share for a total of $130 million. For the year ended Dec. 31, 2007, TransAlta purchased 2,371,800 shares at an average of $31.59 per share for a total of $75 million.

22. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

Year ended Dec. 31	2009	2008	2007
Source (use):			
Accounts receivable	**114**	80	44
Prepaid expenses	**(7)**	3	(3)
Income taxes receivable	**(1)**	(20)	(29)
Inventory	**(42)**	(10)	22
Accounts payable and accrued liabilities	**(208)**	157	32
Income taxes payable	**(5)**	–	–
Change in non-cash operating working capital	**(149)**	210	66

23. CAPITAL

TransAlta's components of capital are listed below:

As at Dec. 31	2009	2008	Increase/ (decrease)
Current portion of long-term debt	**31**	244	(213)
Less: cash and cash equivalents	**(82)**	(50)	(32)
	(51)	194	(245)
Long-term debt			
Recourse	**3,857**	2,332	1,525
Non-recourse	**554**	232	322
Non-controlling interests	**478**	469	9
Common shareholders' equity			
Common shares	**2,169**	1,761	408
Retained earnings	**634**	688	(54)
AOCI	**126**	61	65
	7,818	5,543	2,275
Total capital	**7,767**	5,737	2,030

The long-term portion of recourse debt increased from Dec. 31, 2008 as a result of the issuance of senior notes and debentures primarily related to the acquisition of Canadian Hydro. This increase in long-term debt was partially offset by scheduled repayments and changes in exchange rates.

TransAlta's strategy for managing capital remained unchanged from Dec. 31, 2008.

TransAlta's objectives in managing capital are to:

A. Maintain an Investment Grade Credit Rating:

The Corporation operates in a long-cycle and capital intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable rates. TransAlta monitors key capital ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and manages capital in line with those expectations:

Cash flow to interest coverage Cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest income. TransAlta targets this ratio to be in a range of four to five times.

Cash flow to debt Cash flow from operating activities before changes in working capital divided by average total debt. TransAlta targets this ratio to be 20 to 25 per cent.

Debt to invested capital Debt less cash and cash equivalents divided by debt, non-controlling interests, and shareholders' equity less cash and cash equivalents. TransAlta targets this ratio to be 55 to 60 per cent.

These ratios are presented below:

Year ended Dec. 31	2009	2008
Cash flow to interest coverage (times)[1]	**4.9**	7.2
Cash flow to debt (%)[1]	**20.1**	31.1
Debt to invested capital (%)	**56.1**	48.1

1 Last 12 months.

The decrease in cash flow to interest coverage resulted from decreased cash flows from operating activities and higher interest expense. The decrease in cash flow to debt resulted from a decrease in cash flows from operating activities and an increase in debt balances *(Note 17)*. The increase in debt to invested capital resulted from an increase in debt balances *(Note 17)*. TransAlta routinely monitors forecasts for net earnings, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Capital Assets:

These amounts are summarized in the table below:

Year ended Dec. 31	2009	2008	Increase/ (decrease)
Cash flow from operating activities	**580**	1,038	(458)
Dividends paid	**(226)**	(212)	(14)
Capital asset expenditures	**(904)**	(1,006)	102
Net cash outflow	**(550)**	(180)	(370)

The decrease in the total net cash flows primarily resulted from lower cash flows from operating activities. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2009, $0.7 billion of the Corporation's available credit facilities were not drawn.

While any of the existing debentures are outstanding, the Corporation will not issue or in any other manner become liable for any indebtedness, unless the aggregate principal amount of the Corporation's indebtedness, as defined in the Corporation's trust indenture, does not exceed 75 per cent of total capital.

TransAlta's credit facilities are unsecured and provide funds in either Canadian or U.S. currencies. They contain standard terms and conditions including covenants with respect to financial leverage and cash flow coverage that would be considered typical of bank credit facilities of this nature.

During 2009, the Corporation issued a total of $600 million in debentures; $200 million was issued in May 2009 at a fixed interest rate of 6.45 per cent, maturing in 2014 and $400 million was issued in November 2009 at a fixed rate of 6.4 per cent, maturing in 2019. Both issuances have financial terms and conditions similar to the other debentures of the Corporation. The financial terms and conditions of all other debentures remain unchanged from Dec. 31, 2008. During 2009, the Corporation also issued U.S.$500 million in senior notes at an interest rate of 4.75 per cent and mature in 2015.

During 2009, the Corporation issued 20.8 million common shares for total net proceeds of $408 million.

TransAlta's formal dividend policy targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable net earnings. TransAlta's management defines comparable net earnings as net earnings adjusted for items that would not be considered to be part of normal operations.

24. ACQUISITIONS AND DISPOSALS

A. Acquisitions

On Oct. 23, 2009, TransAlta acquired 87 per cent of Canadian Hydro through the purchase of the issued and outstanding shares of Canadian Hydro. On Nov. 4, 2009, TransAlta acquired the remaining 13 per cent of the issued and outstanding shares. The total cash consideration was $785 million. The results of Canadian Hydro are included in the consolidated financial statements of the Corporation from the acquisition date of Oct. 23, 2009.

The details of the cash consideration are as follows:

Total shares acquired (millions)	143.8
Price per share	5.25
Total consideration paid	755
Transaction costs	30
Total cash consideration	**785**

The allocation of the aggregate purchase price based on the estimated fair values of the assets of Canadian Hydro on the acquisition date is as follows:

Assets:		
Cash	19	
Accounts receivable	25	
Prepaid expenses	5	
Property, plant, and equipment	1,291	
Intangible assets	176	
Development costs	22	
Goodwill	304	
Total assets acquired		1,842
Liabilities:		
Accounts payable and accrued liabilities	54	
Current risk management liabilities	6	
Long-term risk management liabilities	34	
Long-term debt	931	
Future income tax liabilities	29	
Asset retirement obligation	3	
Total liabilities assumed		1,057
Total purchase price		**785**

The long-term risk management liabilities consist of financial contracts used to hedge exposures to fluctuations in electricity prices. These contracts qualify for hedge accounting treatment.

Although TransAlta does not anticipate material changes to this preliminary allocation, the values may change when the evaluation of fair value information is complete. Any subsequent adjustments will be accounted for in the period incurred.

B. Disposals

On Oct. 8, 2008, TransAlta successfully completed the sale of the Mexican equity investment to InterGen for a sale price of $334 million. The sale included the plants at both facilities and all associated commercial arrangements.

The details of the sale are as follows:

Contractual proceeds		334
Less: closing costs		(3)
Net proceeds excluding cash on hand of $1 million		331
Book value of investment		420
Loss before deferred foreign exchange losses		89
Deferred foreign exchange losses on the net assets of the Mexican equity investment	147	
Deferred gains on financial instruments designated as hedges of the net assets of the Mexican equity investment	(148)	
Income tax expense on financial instruments	9	
Deferred foreign exchange losses		8
Loss before income taxes		97
Income tax recovery		35
Net loss		**62**

Included in the book value of the investment is a provision for representations and warranties of $2 million (2008–$13 million).

During 2007, the Mexican equity investment incurred a loss of $50 million.

25. RELATED PARTY TRANSACTIONS

On Jan. 1, 2009, TAU and TransAlta Energy Corporation transferred certain generation and transmission assets to a newly formed internal partnership, TransAlta Generation Partnership ("TAGP"), before amalgamating with TransAlta Corporation.

On Dec.16, 2006, predecessors of TAGP, a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at Dec. 31, 2009, TAGP had received $51 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The total value of these contracts are U.S.$3 million per year 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.

26. 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.

27. COMMITMENTS

The Corporation has entered into a number of long-term gas purchase agreements, transportation and transmission agreements, royalty and right-of-way agreements in the normal course of operations.

Approximate future payments under the fixed price purchase contracts, transmission, operating leases, mining agreements, interest on long-term debt, and growth project commitments are as follows:

	Fixed price gas purchase contracts	Transmission	Operating leases	Coal supply and mining agreements	Long-term service agreement	Interest on long-term debt[1]	Growth project commitments	Total
2010	8	–	10	51	14	224	497	804
2011	7	2	10	47	16	203	87	372
2012	7	3	9	47	16	183	14	279
2013	7	3	9	47	16	170	–	252
2014	7	3	8	51	16	142	–	227
2015 and thereafter	25	38	56	269	18	600	–	1,006
Total	**61**	**49**	**102**	**512**	**96**	**1,522**	**598**	**2,940**

1 Includes impact of derivatives.

A. Fixed Price Gas Purchase Contracts

Centralia Gas and the Corporation's Australia operations have contracts in place for the fixed portion of the gas costs at the plants.

B. Transmission

During 2008, TransAlta entered into several five-year agreements with Bonneville Power Administration Transmission ("BPAT") to purchase 400 megawatts ("MW") of Pacific Northwest transmission network capacity. Provided BPAT can meet certain conditions for delivering the service, the Corporation is committed to taking the services at BPAT's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Operating Leases

TransAlta has operating leases in place for buildings, vehicles and various types of equipment.

D. Coal Supply and Mining Agreements

At Centralia Thermal, a significant portion of production is subject to short- to medium-term energy sales contracts. Centralia Thermal also has various coal supply and associated rail transport contracts to provide coal for use in production. During 2008, TransAlta entered into various coal supply agreements with three suppliers for the Centralia Thermal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates ranging from June 1, 2008 to Dec. 31, 2013.

At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal.

E. Long-Term Service Agreements

TransAlta has various service agreements in place primarily for repairs and maintenance that may be required on turbines at various wind generating facilities.

F. Growth Project Commitments

On Jan. 11, 2010, TransAlta announced the expansion of its existing 96 MW Kent Hills wind facility. The capital cost of the project is estimated at $100 million and is expected to begin commercial operations by the end of 2010. As at Dec. 31, 2009 total capital incurred on this project was $18 million. Natural Forces will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

As part of the acquisition of Canadian Hydro on Oct. 23, 2009, TransAlta assumed the plans to design, build, and operate Bone Creek, an 18 MW hydro facility in British Columbia. The capital cost of the project is estimated at $48 million and is expected to begin commercial operations in the first quarter of 2011. As at Dec. 31, 2009, the total capital incurred on this project was $4 million.

On April 28, 2009, TransAlta announced plans to design, build, and operate Ardenville, a 69 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the purchase was an operational 3 MW wind power project in southern Alberta. As at Dec. 31, 2009, the total capital incurred on this project was $27 million. Commercial operations of the remainder of the facility are expected to commence in the first quarter of 2011.

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. As at Dec. 31, 2009, the total capital incurred on these projects was $2 million.

On May 27, 2008, TransAlta announced a 66 MW expansion of its Summerview wind farm located in southern Alberta near Pincher Creek. The capital cost of the project is estimated at $123 million with construction commencing in the second quarter of 2009 and commercial operations expected to begin in the first quarter of 2010. As at Dec. 31, 2009, total capital spend on this project was $106 million. Commercial operations commenced on Feb. 23, 2010 and the total capital cost of the project was $123 million *(Note 33)*.

Keephills 3 plant construction and associated mine capital costs are anticipated to be approximately $1.9 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $988 million. As at Dec. 31, 2009, total spend on this project was $707 million.

On June 21, 2007, TAGP entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal to the Keephills 3 joint venture project. The total dragline purchase costs include approximately $121 million for the purchase of the equipment, and an additional $29 million for the assembly and commissioning of the dragline, for a total of approximately $150 million, with final payments for goods and services due by completion and acceptance of the asset in the third quarter of 2010. As at Dec. 31, 2009, total payments under this agreement were $125 million.

Growth project commitments are as follows:

	Kent Hills	Bone Creek	Ardenville	Keephills Unit 1 uprate	Keephills Unit 2 uprate	Summerview	Keephills Unit 3	Total
2010	82	44	108	3	5	17	238	497
2011	–	–	–	30	14	–	43	87
2012	–	–	–	–	14	–	–	14
2013	–	–	–	–	–	–	–	–
2014	–	–	–	–	–	–	–	–
2015 and thereafter	–	–	–	–	–	–	–	–
Total	**82**	**44**	**108**	**33**	**33**	**17**	**281**	**598**

G. Other

A significant portion of the Corporation's electricity and thermal sales revenues are subject to PPAs and long-term contracts. Commencing Jan. 1, 2001, a large portion of Alberta's coal generating assets became subject to long-term PPAs for a period approximating the remaining life of each plant or unit. These PPAs set a production requirement and availability target for each plant or unit and the price at which each MWh will be supplied to the customer. Remaining coal capacity in Alberta is sold on the open electricity market.

A portion of Poplar Creek's electrical and all of its steam capacity is committed to the customer under a long-term contract. The remaining electrical capacity may be taken by the customer at market prices or sold on the open electricity market by TransAlta. Other gas-fired facilities in Alberta supply steam and/or electricity to specified customers under long-term contracts with additional requirements for availability, reliability, and other plant-specific performance measures.

Sarnia has 20-year contracts with a customer group with three five-year options for extensions to the contracts. The contracts allow for up to 40 per cent of the plant's maximum capacity. These contracts set payments for peak MWs, total MWhs supplied to the customers and steam consumed, while TransAlta assumes the availability and heat rate risk. On Sept. 30, 2009, TransAlta signed a new agreement with the Ontario Power Authority to supply up to 444 MWs of electricity to the Ontario electricity market, which was effective on July 1, 2009 and expires on Dec. 31, 2025. The remaining capacity at Sarnia is available for export to the merchant market, based on market prices. Electrical production at the remaining Ontario plants is subject to contracts expiring in three to eight years.

Mississauga, Windsor-Essex, and Ottawa have contracts that set availability targets and the price at which the plant will be paid per MWh produced, as well as risk sharing of fuel costs based on market prices. Thermal energy contracts for Mississauga and Windsor expire at the same time as the energy production contracts and are with a different customer base. Ottawa has thermal contracts with three different customers. The contract with the main customer expires at the end of 2022. These contracts set payments for volumes consumed, while TA Cogen assumes the heat rate risk. On Oct. 12, 2007, the Corporation signed an agreement amending the original PPA with the Ontario Electricity Financial Corporation ("OEFC") for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant production following the expiry of long-term natural gas supply contracts. The agreement is in effect from Nov. 1, 2007 until Dec. 31, 2012.

28. PRIOR PERIOD REGULATORY DECISION

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the *Federal Power Act* ("FPA"), the Federal Energy Regulatory Commission ("FERC") established a claim of approximately U.S.$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange ("PX") and the California Independent System Operator ("ISO") during the Oct. 2, 2000 through June 20, 2001 period (the "Main Refund Transactions"). TransAlta has provided U.S.$46 million to account for refund liabilities relating to Main Refund Transactions. TransAlta filed a cost-of-service-based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006, TransAlta filed for rehearing of FERC's rejection. On Aug. 24, 2007, the U.S. Court of Appeals for the Ninth Circuit granted the appeal. TransAlta has requested a rehearing; however, FERC has yet to make a ruling on such a request and such a decision is not expected in the near future.

During settlement negotiations, the California parties have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (the "Summer Transactions"). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources ("CDWR") referred to as CERS (the "CERS Transactions"). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. The Ninth Circuit held that FERC's authorization of market-based rate tariffs in these proceedings complied with the FPA, but that FERC erred in refusing refunds on the grounds that it lacked authority to order refunds for violations of its reporting requirement and remanded the case for further refund proceedings. The court did not itself order any refunds, leaving it to FERC to consider appropriate remedial options.

On March 21, 2008, FERC issued an Order on Remand establishing a refund hearing before an Administrative Law Judge to determine whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable in California during the 2000–2001 period. The California parties appealed FERC's basis for determining refund liability but the appeal was denied by FERC on Oct. 6, 2008. The California Parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. In a decision issued Aug. 24, 2007, which denied rehearing remanded matters to FERC, the Ninth Circuit ruled that FERC had properly excluded both the Summer Transactions and the CERS Transactions from the complaint proceeding. FERC has yet to respond to the remand.

TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

29. SEGMENT DISCLOSURES

A. Description of Reportable Segments

The Corporation has two reportable segments as described in Note 1.

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

Generation expenses include COD's intersegment charge for energy marketing and financial risk management services in the amount of $32 million (2008–$30 million, 2007–$27 million). COD's operating expenses are presented net of these intersegment charges.

The accounting policies of the segments are the same as those described in Note 1. Intersegment transactions are accounted for on a cost-recovery basis that approximates market rates.

B. Reported Segment Earnings and Segment Assets

I. Earnings information

Year ended Dec. 31, 2009	Generation	COD	Corporate	Total
Revenues	**2,723**	**47**	**–**	**2,770**
Fuel and purchased power	**(1,228)**	**–**	**–**	**(1,228)**
	1,495	**47**	**–**	**1,542**
Operations, maintenance, and administration	**550**	**31**	**86**	**667**
Depreciation and amortization	**453**	**4**	**18**	**475**
Taxes, other than income taxes	**22**	**–**	**–**	**22**
Intersegment cost allocation	**32**	**(32)**	**–**	**–**
	1,057	**3**	**104**	**1,164**
	438	**44**	**(104)**	**378**
Foreign exchange gain *(Note 7)*				**8**
Writedown of mining development costs *(Note 3)*				**(16)**
Net interest expense *(Notes 7 and 17)*				**(144)**
Other income *(Note 4)*				**8**
Earnings before non-controlling interests and income taxes				**234**

Year ended Dec. 31, 2008	Generation	COD	Corporate	Total
Revenues	3,005	105	–	3,110
Fuel and purchased power	(1,493)	–	–	(1,493)
	1,512	105	–	1,617
Operations, maintenance, and administration	487	53	97	637
Depreciation and amortization	409	3	16	428
Taxes, other than income taxes	19	–	–	19
Intersegment cost allocation	30	(30)	–	–
	945	26	113	1,084
	567	79	(113)	533
Foreign exchange loss *(Note 7)*				(12)
Net interest expense *(Notes 7 and 17)*				(110)
Equity loss *(Note 24)*				(97)
Other income *(Note 4)*				5
Earnings before non-controlling interests and income taxes				319

Year ended Dec. 31, 2007	Generation	COD	Corporate	Total
Revenues	2,720	55	–	2,775
Fuel and purchased power	(1,231)	–	–	(1,231)
	1,489	55	–	1,544
Operations, maintenance, and administration	447	34	96	577
Depreciation and amortization	391	1	14	406
Taxes, other than income taxes	20	–	–	20
Intersegment cost allocation	27	(27)	–	–
	885	8	110	1,003
	604	47	(110)	541
Foreign exchange gain *(Note 7)*				3
Net interest expense *(Notes 7 and 17)*				(133)
Equity loss *(Note 24)*				(50)
Other income *(Note 4)*				16
Earnings before non-controlling interests and income taxes				377

Included above in Generation is $9 million (2008–$5 million, 2007–$5 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

II. Selected Consolidated Balance Sheets information

As at Dec. 31, 2009	Generation	COD	Corporate	Total
Goodwill *(Note 14)*	**404**	**30**	**–**	**434**
Total segment assets	**9,133**	**148**	**481**	**9,762**

As at Dec. 31, 2008				
Goodwill *(Note 14)*	112	30	–	142
Total segment assets	7,119	206	499	7,824

A portion of goodwill is related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

III. Selected Consolidated Statements of Cash Flows information

Year ended Dec. 31, 2009	Generation	COD	Corporate	Total
Capital expenditures	**879**	**5**	**20**	**904**

Year ended Dec. 31, 2008				
Capital expenditures	992	7	7	1,006

Year ended Dec. 31, 2007				
Capital expenditures	577	5	17	599

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

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

Year ended Dec. 31	2009	2008	2007
Depreciation and amortization expense on the Consolidated Statements of Earnings	**475**	428	406
Depreciation included in fuel and purchased power	**40**	38	30
Accretion expense included in depreciation and amortization expense	**(24)**	(22)	(24)
Other	**2**	7	3
Depreciation and amortization on the Consolidated Statements of Cash Flows	**493**	451	415

C. Geographic Information

I. Revenues

Year ended Dec. 31	2009	2008	2007
Canada	**1,631**	1,839	1,742
U.S.	**1,042**	1,165	932
Australia	**97**	106	101
Total revenue	**2,770**	3,110	2,775

II. Property, Plant, and Equipment and Goodwill

	Property, Plant, and Equipment *(Note 13)*		Goodwill *(Note 14)*	
As at Dec. 31	2009	2008	2009	2008
Canada	**6,220**	4,464	**360**	57
U.S.	**1,182**	1,418	**74**	85
Australia	**176**	152	**–**	–
Total	**7,578**	6,034	**434**	142

A change in foreign exchange rates from 2008 to 2009 has resulted in a $179 million decrease in net book value of PP&E and a $12 million decrease in goodwill. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect net earnings; rather any cumulative translation gains and losses are reflected in AOCI.

30. STOCK-BASED COMPENSATION PLANS

At Dec. 31, 2009, the Corporation had two types of stock-based compensation plans and an employee share purchase plan.

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

A. Fixed Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. U.S. Plan

This plan mirrors the rules of the Canadian plan.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia, excluding directors and officers. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

The total options outstanding and exercisable under these fixed stock option plans at Dec. 31, 2009 are shown below:

	Options outstanding			Options exercisable	
Range of exercise prices (per share)	Number outstanding at Dec. 31, 2009 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price (per share)	Number exercisable at Dec. 31, 2009 (millions)	Weighted average exercise price (per share)
11.47–17.70	0.2	2.9	14.81	0.2	14.81
17.71–23.94	0.4	4.2	18.81	0.4	18.81
23.95–30.18	0.1	1.3	27.70	0.1	27.70
30.19–36.41	0.8	8.1	32.29	0.2	32.29
11.47–36.41	1.5	5.9	26.36	0.9	22.28

The change in the number of options outstanding under the fixed option plans are outlined below:

Year ended Dec. 31	2009		2008		2007	
	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)
Outstanding, beginning of year	**1.7**	**26.80**	1.2	19.69	2.2	20.20
Granted	–	–	1.0	32.10	–	–
Exercised	–	–	(0.3)	20.52	(0.8)	21.39
Cancelled or expired	**(0.2)**	**26.47**	(0.2)	27.96	(0.2)	17.52
Outstanding, end of year	**1.5**	**26.36**	1.7	26.80	1.2	19.69

B. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to grant to employees and directors up to an aggregate of 4.0 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, can not exceed 13.0 million common shares. Participants in the PSOP receive grants which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. Once a participant's PSOP eligibility has been established, 50 per cent of the shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the Corporation's common shares amongst the companies comprising the comparator group. Expense related to this plan is recorded during the period earned, with the corresponding payable recorded in liabilities.

Year ended Dec. 31 (millions)	2009	2008	2007
Number of awards outstanding, beginning of year	**0.9**	1.0	1.2
Granted	**0.5**	0.2	0.4
Exercised	**(0.2)**	(0.2)	(0.1)
Cancelled or expired	**(0.2)**	(0.1)	(0.5)
Number of awards outstanding, end of year	**1.0**	0.9	1.0

In 2009, PSOP compensation expense was $7 million after-tax (2008–$5 million after-tax, 2007–$7 million after-tax), which is included in OM&A expense in the Consolidated Statements of Earnings. In 2009, 224,591 common shares were issued at $22.08 per share. In 2008, 221,855 common shares were issued at $24.30 per share. In 2007, 103,896 common shares were issued at $33.35 per share.

C. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are not eligible for this program in accordance with the Sarbanes-Oxley legislation. The Corporation will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2009, accounts receivable from employees under the plan totalled $3 million (2008–$3 million).

D. Stock-Based Compensation

At Dec. 31, 2009, the Corporation had 1.5 million outstanding employee stock options (2008–1.7 million).

The Corporation uses the fair value method of accounting for awards granted under its fixed stock option plans.

The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model in 2008 and the binomial model in 2005 and 2002 using the following assumptions:

	2008	2005	2002
Weighted average fair value per option	6.31	6.84	4.25
Risk-free interest rate (%)	3.6	4.3	5.9
Expected life of the options (years)	7	10	7
Dividend rate (%)	3.4	5.6	4.9
Volatility in the price of the Corporation's shares (%)	23.2	47.0	28.3

31. EMPLOYEE FUTURE BENEFITS

A. Description

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

The latest actuarial valuations for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2009. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2009. The last actuarial valuation for funding purposes of the registered plan was Dec. 31, 2007, and the effective date of the next required valuation for funding purposes is Dec. 31, 2010. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $58 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2007. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2009.

B. Costs Recognized

The costs recognized during the year on the defined benefit, defined contribution, and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Current service cost	**2**	**1**	**2**	**5**
Interest cost	**22**	**3**	**2**	**27**
Actual return on plan assets	**(38)**	**–**	**–**	**(38)**
Actuarial loss	**36**	**7**	**13**	**56**
Difference between expected return and actual return on plan assets	**19**	**–**	**–**	**19**
Difference between amortized and actuarial gain on accrued benefit obligation for the year	**(33)**	**(6)**	**(12)**	**(51)**
Amortization of net transition asset	**(9)**	**–**	**–**	**(9)**
Defined benefit (income) expense	**(1)**	**5**	**5**	**9**
Defined contribution option expense of registered pension plan	**18**	**–**	**–**	**18**
Net expense	**17**	**5**	**5**	**27**

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Current service cost	3	1	1	5
Interest cost	20	3	1	24
Actual return on plan assets	55	–	–	55
Actuarial gain	(49)	(5)	(4)	(58)
Difference between expected return and actual return on plan assets	(79)	–	–	(79)
Difference between amortized and actuarial loss on accrued benefit obligation for the year	50	6	5	61
Past service costs	–	2	–	2
Difference between amortized and actual plan amendments of past service costs for the year	–	(2)	–	(2)
Amortization of net transition asset	(9)	–	–	(9)
Defined benefit (income) expense	(9)	5	3	(1)
Defined contribution option expense of registered pension plan	17	–	–	17
Net expense	8	5	3	16

Year ended Dec. 31, 2007	Registered	Supplemental	Other	Total
Current service cost	4	2	1	7
Interest cost	19	2	2	23
Actual return on plan assets	(10)	–	–	(10)
Actuarial (gain) loss	(15)	6	(2)	(11)
Difference between expected return and actual return on plan assets	(15)	–	–	(15)
Difference between amortized and actuarial loss (gain) on accrued benefit obligation for the year	16	(4)	2	14
Amortization of net transition asset	(9)	–	–	(9)
Defined benefit (income) expense	(10)	6	3	(1)
Defined contribution option expense of registered pension plan	15	–	–	15
Net expense	5	6	3	14

In 2009, 2008, and 2007, the entire net expense is related to continuing operations.

C. Status of Plans

The status of the defined benefit and other health and dental benefit plans is as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Fair value of plan assets	**299**	**3**	**–**	**302**
Accrued benefit obligation	**358**	**55**	**33**	**446**
Funded status–plan deficit	**(59)**	**(52)**	**(33)**	**(144)**
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	**1**	**2**	**2**	**5**
Unamortized transition (asset) obligation	**(9)**	**1**	**–**	**(8)**
Unamortized net actuarial gains	**85**	**15**	**11**	**111**
Total recognized in the consolidated financial statements:				
Accrued benefit asset (liability)	**18**	**(34)**	**(20)**	**(36)**
Amortization period in years	**14**	**14**	**15**	

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Fair value of plan assets	279	3	–	282
Accrued benefit obligation	324	47	20	391
Funded status–plan deficit	(45)	(44)	(20)	(109)
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	–	1	3	4
Unamortized transition (asset) obligation	(18)	1	–	(17)
Unamortized net actuarial gains	72	9	–	81
Total recognized in the consolidated financial statements:				
Accrued benefit liability	9	(33)	(17)	(41)
Amortization period in years	15	13	15	

The current portion of the accrued benefit liability is included in accounts payable and accrued liabilities on the Consolidated Balance Sheets. The long-term portion is included in other assets and deferred credits and other long-term liabilities.

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Accrued current liabilities	**–**	**3**	**2**	**5**
Other long-term (assets) liabilities	**(18)**	**31**	**18**	**31**
Accrued benefit (asset) liability	**(18)**	**34**	**20**	**36**

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Accrued current liabilities	–	–	1	1
Other long-term (assets) liabilities	(9)	33	16	40
Accrued benefit (asset) liability	(9)	33	17	41

D. Contributions

Expected cash flows on the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2010 (expected)	6	3	3	12
Expected benefit payments				
2010	26	3	3	32
2011	27	3	3	33
2012	27	3	3	33
2013	27	3	3	33
2014	28	3	3	34
2015–2019	141	18	14	173

E. Plan Assets

The plan assets of the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Fair value of plan assets at Dec. 31, 2007	356	2	–	358
Contributions	3	4	2	9
Benefits paid	(27)	(3)	(2)	(32)
Effect of translation on U.S. plans	2	–	–	2
Actual return on plan assets[1]	(55)	–	–	(55)
Fair value of plan assets at Dec. 31, 2008	279	3	–	282
Contributions	7	3	2	12
Benefits paid	(26)	(3)	(2)	(31)
Benefits transferred in[2]	4	–	–	4
Effect of translation on U.S. plans	(3)	–	–	(3)
Actual return on plan assets[1]	38	–	–	38
Fair value of plan assets at Dec. 31, 2009	**299**	**3**	**–**	**302**

1 Net of expenses.
2 Transfer of pension assets for addition of employees.

The Corporation's investment policy is to seek a consistently high investment return over time while maintaining an acceptable level of risk to satisfy the benefit obligations of the pension plans. The goal is to maintain a long-term rate of return on the fund that at least equals the growth of liabilities, currently seven per cent. The pension fund may be invested in a variety of permitted investments including publicly traded common or preferred shares, rights or warrants, convertible debentures or preferred securities, bonds, debentures, mortgages, notes or other debt instruments of government agencies or corporations, private company securities, guaranteed investment contracts, term deposits, cash or money market securities, and mutual or pooled funds eligible for pension fund investment. The targeted asset allocation is 50 per cent equity and 50 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investments or as defensive reserves within the portfolios of each asset class. The fund may invest in derivatives for the purpose of hedging the portfolio or altering the desired mix of the fund. Derivative transactions that leverage the fund in any way are not permitted without the specific approval of the Corporation's Pension Committee.

The allocation of defined benefit plan assets by major asset category at Dec. 31, 2009 and 2008 is as follows:

Year ended Dec. 31, 2009	Registered	Supplemental
Equity securities	**52%**	**–**
Debt securities	**45%**	**–**
Cash and cash equivalents	**3%**	**100%**
Total	**100%**	**100%**

Year ended Dec. 31, 2008	Registered	Supplemental
Equity securities	51%	–
Debt securities	48%	–
Cash and cash equivalents	1%	100%
Total	100%	100%

Plan assets do not include any common shares of the Corporation at Dec. 31, 2009. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2009 (2008–$0.1 million).

The fair value of the total defined benefit plan assets by major asset category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	132	11	12	155
Debt securities	125	11	–	136
Cash and cash equivalents	11	–	–	11
Total	**268**	**22**	**12**	**302**

The fair value of the Canadian defined benefit plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	132	–	12	144
Debt securities	125	–	–	125
Cash and cash equivalents	7	–	–	7
Total	**264**	**–**	**12**	**276**

The fair value of the U.S. defined benefit plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	–	11	–	11
Debt securities	–	11	–	11
Cash and cash equivalents	1	–	–	1
Total	**1**	**22**	**–**	**23**

The fair value of the supplemental plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	–	–	–	–
Debt securities	–	–	–	–
Cash and cash equivalents	3	–	–	3
Total	**3**	**–**	**–**	**3**

F. Accrued Benefit Obligation

The accrued benefit obligation on the defined benefit and other health and dental benefit plans is as follows:

	Registered	Supplemental	Other	Total
Accrued benefit obligation as at Dec. 31, 2007	373	49	23	**445**
Current service cost	3	1	1	**5**
Past service cost	–	2	–	**2**
Interest cost	20	3	1	**24**
Benefits paid	(27)	(3)	(2)	**(32)**
Effect of translation on U.S. plans	4	–	1	**5**
Actuarial gain	(49)	(5)	(4)	**(58)**
Accrued benefit obligation as at Dec. 31, 2008	324	47	20	**391**
Current service cost	2	1	2	**5**
Interest cost	22	3	2	**27**
Benefits paid	(26)	(3)	(2)	**(31)**
Benefits transferred in[1]	4	–	–	**4**
Effect of translation on U.S. plans	(4)	–	(2)	**(6)**
Actuarial loss	36	7	13	**56**
Accrued benefit obligation as at Dec. 31, 2009	**358**	**55**	**33**	**446**

1 Transfer of accrued benefit obligation for addition of employees.

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation on the defined benefit and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	**6.0**	**6.0**	**5.7**
Rate of compensation increase (%)	**3.0**	**3.0**	**–**
Benefit cost for year ended Dec. 31			
Discount rate (%)	**7.2**	**7.3**	**7.0**
Rate of compensation increase (%)	**3.2**	**3.3**	**–**
Expected rate of return on plan assets (%)	**7.1**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	**–**	**–**	**9.2–10.5**[1]
Dental care cost escalation (%)	**–**	**–**	**4.0**
Provincial health care premium escalation (%)	**–**	**–**	**6.0**

Year ended Dec. 31, 2008	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	7.2	7.3	7.1
Rate of compensation increase (%)	3.2	3.3	–
Benefit cost for year ended Dec. 31			
Discount rate (%)	5.5	5.5	5.7
Rate of compensation increase (%)	3.7	3.8	–
Expected rate of return on plan assets (%)	7.1	–	–
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	–	–	9.0–10.5[1]
Dental care cost escalation (%)	–	–	4.0
Provincial health care premium escalation (%)	–	–	2.5

1 Decreasing gradually to five per cent by 2018 for Canadian plans and by 2017–2020 for U.S. plans and remaining at that level thereafter.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan.

H. Sensitivity Analysis

The following changes would occur in the defined benefit and other health and dental benefit plans if there was a change of +/– one percentage point in the discount rate, trend rate, or expected rate of return on plan assets:

Canadian plans:

Year ended Dec. 31, 2009	Registered	Supplemental	Other
1% increase in the discount rate			
Impact on 2009 accrued benefit obligation	**(30)**	**(6)**	**(1)**
Impact on 2010 estimated expense	**(1)**	**(1)**	**–**
1% decrease in the discount rate			
Impact on 2009 accrued benefit obligation	**35**	**8**	**2**
Impact on 2010 estimated expense	**1**	**1**	**–**
1% increase in the trend rate			
Impact on 2009 accrued benefit obligation	**–**	**–**	**2**
Impact on 2010 estimated expense	**–**	**–**	**–**
1% decrease in the trend rate			
Impact on 2009 accrued benefit obligation	**–**	**–**	**(1)**
Impact on 2010 estimated expense	**–**	**–**	**–**
1% increase in the expected rate of return on plan assets			
Impact on 2010 estimated expense	**(3)**	**–**	**–**
1% decrease in the expected rate of return on plan assets			
Impact on 2010 estimated expense	**3**	**–**	**–**

U.S. plans:

Year ended Dec. 31, 2009	Pension	Other
1% increase in the discount rate		
Impact on 2009 accrued benefit obligation	**(2)**	**(1)**
Impact on 2010 estimated expense	**–**	**–**
1% decrease in the discount rate		
Impact on 2009 accrued benefit obligation	**3**	**1**
Impact on 2010 estimated expense	**–**	**–**
1% increase in the trend rate		
Impact on 2009 accrued benefit obligation	**–**	**2**
Impact on 2010 estimated expense	**–**	**–**
1% decrease in the trend rate		
Impact on 2009 accrued benefit obligation	**–**	**(1)**
Impact on 2010 estimated expense	**–**	**–**
1% increase in the expected rate of return on plan assets		
Impact on 2010 estimated expense	**–**	**–**
1% decrease in the expected rate of return on plan assets		
Impact on 2010 estimated expense	**–**	**–**

32. JOINT VENTURES

Joint ventures at Dec. 31, 2009 included the following:

Joint venture		Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Canadian Utilities Limited
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia operated by TransAlta
CE Generation LLC	50%	Geothermal and gas plants in the United States operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta operated by Capital Power Corporation
Wailuku	50%	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company
Keephills 3	50%	Coal-fired plant under construction in Alberta. The plant is being developed jointly with Capital Power Corporation and will be operated by TransAlta
Taylor Hydro	50%	Hydro facility in Alberta operated by TransAlta
Soderglen	50%	Wind generation facilities in Alberta operated by TransAlta
Pingston	50%	Hydro facility in British Columbia operated by TransAlta

Summarized information on the results of operations, financial position and cash flows relating to the Corporation's pro-rata interests in its jointly controlled corporations was as follows:

	2009	2008	2007
Results of operations			
Revenues	**539**	619	609
Expenses	**(409)**	(494)	(454)
Non-controlling interests	**(34)**	(55)	(44)
Proportionate share of net earnings	**96**	70	111
Cash flows			
Cash flow from operations	**111**	273	112
Cash flow used in investing activities	**(168)**	(376)	(147)
Cash flow (used in) from financing activities	**(60)**	30	(93)
Proportionate share of decrease in cash and cash equivalents	**(117)**	(73)	(128)
Financial position			
Current assets	**147**	166	91
Long-term assets	**2,371**	2,144	1,924
Current liabilities	**(114)**	(202)	(144)
Long-term liabilities	**(356)**	(503)	(390)
Non-controlling interests	**(325)**	(351)	(373)
Proportionate share of net assets	**1,723**	1,254	1,108

33. SUBSEQUENT EVENTS

TransAlta has evaluated subsequent events through to Feb. 23, 2010, which represents the date the consolidated financial statements were issued. TransAlta has not evaluated any subsequent events after that date.

Summerview 2

On Feb. 23, 2010, the 66 MW Summerview 2 wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was $123 million.

Kent Hills Expansion

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

ELEVEN-YEAR FINANCIAL AND STATISTICAL SUMMARY

(in millions of Canadian dollars, except where noted)

	2009	2008	2007
FINANCIAL SUMMARY			
CONSOLIDATED STATEMENTS OF EARNINGS			
Revenues	**2,770**	3,110	2,775
Operating income	**378**	533	541
Net earnings applicable to common shareholders	**181**	235	309
CONSOLIDATED BALANCE SHEETS			
Total assets	**9,762**	7,815	7,157
Current portion of long-term debt, net of cash and cash equivalents	**(51)**	194	600
Long-term debt	**4,411**	2,564	1,837
Preferred shares of a subsidiary	**–**	–	–
Other non-controlling interests	**478**	469	496
Preferred securities	**–**	–	–
Common shareholder's equity	**2,929**	2,510	2,299
Total invested capital	**7,767**	5,737	5,232
CONSOLIDATED STATEMENTS OF CASH FLOWS			
Cash flow from operating activities	**580**	1,038	847
Cash flow used in investing activities	**(1,598)**	(581)	(410)
COMMON SHARE INFORMATION (per share)			
Net earnings	**0.90**	1.18	1.53
Comparable earnings[3]	**0.90**	1.46	1.31
Dividends declared	**1.16**	1.08	1.00
Book value (at year-end)	**13.41**	12.70	11.39
Market price:			
High	**25.30**	37.50	34.00
Low	**18.11**	21.00	23.79
Close (Toronto Stock Exchange at Dec. 31)	**23.48**	24.30	33.35
RATIOS (percentage except where noted)			
Debt to invested capital	**56.1**	48.1	46.8
Debt to invested capital excluding non-recourse debt	**52.6**	45.6	44.0
Return on shareholder's equity	**6.9**	9.4	13.1
Comparable return on shareholder's equity[3]	**6.9**	11.6	10.5
Return on capital employed	**5.7**	7.7	9.8
Comparable return on capital employed[3]	**5.8**	9.6	9.7
Price/earnings ratio	**26.1**	20.6	21.8
Earnings coverage (times)	**1.9**	2.8	3.3
Dividend payout ratio	**129.8**	91.5	65.6
Dividend payout ratio based on comparable earnings[3]	**129.8**	74.1	76.4
EBITDA (in millions of Canadian dollars)[3]	**895**	1,006	980
Dividend coverage (times)	**2.5**	4.8	4.2
Dividend yield	**4.9**	4.4	3.0
Cash flow to debt	**20.1**	31.1	30.7
Cash flow to interest coverage (times)	**4.9**	7.2	6.6
Weighted average common shares for the year (in millions)	**201**	199	202
Common shares outstanding at Dec. 31 (in millions)	**218**	198	201
STATISTICAL SUMMARY			
Number of employees	**2,343**	2,200	2,201
GENERATING CAPACITY (net MW)[4]			
Hydro	**893**	807	807
Coal	**4,967**	4,942	4,942
Gas	**1,843**	1,913	1,960
Renewables	**1,072**	411	315
Total generating capacity	**8,775**	8,073	8,024
Total generation production (GWh)[5]	**45,736**	48,891	50,395

Prior years have not been restated to conform with the current year's presentation.

1 *2002 and 2001 Energy Marketing real-time trading contract revenues are restated to be presented on a gross basis.*

2 *Includes discontinued operations.*

3 *These ratios were calculated using non-GAAP measures. Periods for which the non-GAAP measure was not previously disclosed have not been calculated.*

4 *Represents TransAlta's ownership.*

5 *Includes discontinued operations.*

Ratio Formulas

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

Return on shareholder's equity = net earnings excluding gain on discontinued operations or comparable earnings / average shareholder's equity excluding Accumulated Other Comprehensive Income ("AOCI")

2006	2005	2004	2003	2002	2001	2000	1999
2,677	2,664	2,838	2,509	1,815[1]	2,560[1]	1,587	1,029
157	421	478	554	224[2]	469[2]	605[2]	442
45	199	170	234	190	215	280	170
7,460	7,741	8,133	8,420	7,420	7,878	7,627	6,038
296	(66)	(103)	(35)	146	475	221	(173)
2,221	2,605	3,058	3,162	2,707	2,511	2,201	2,177
–	–	–	–	–	–	122	268
535	559	616	478	263	281	253	377
175	175	175	451	452	453	292	287
2,428	2,543	2,473	2,460	2,040	1,990	1,957	1,836
5,655	5,756	6,061	6,516	5,608	5,710	5,046	4,772
490	619	613	757	438	716	189	422
(261)	(242)	(65)	(535)	(36)	(1,077)	(205)	(989)
0.22	1.01	0.88	1.26	1.12	1.27	1.66	1.00
1.16	0.88	0.70	0.69	0.99	–	–	–
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
11.99	12.80	12.74	12.90	12.01	11.82	11.61	10.85
26.91	26.66	18.75	19.55	23.95	30.13	22.55	25.15
20.22	17.67	15.25	15.36	16.69	19.15	13.20	12.25
26.64	25.41	18.05	18.53	17.11	21.60	22.00	14.15
44.5	43.9	47.4	47.9	50.9	52.3	48.0	45.6
41.0	39.9	42.5	42.9	–	–	–	–
1.8	7.0	6.5	10.3	3.5	10.9	11.7	9.2
9.2	6.8	5.1	5.6	8.2	–	–	–
2.4	7.1	7.5	9.1	4.0	8.7	12.3	9.7
9.0	7.4	–	–	–	–	–	–
121.1	26.7	21.7	14.7	41.7	17.3	16.7	14.2
0.5	2.3	1.9	2.0	1.9	3.0	4.0	3.8
447.7	113.0	120.0	79.0	241.8	78.5	75.8	99.7
86.0	113.3	150.4	143.7	100.6	–	–	–
–	–	–	–	–	–	–	–
2.4	3.1	3.2	4.1	2.6	4.3	1.1	2.5
3.8	3.9	5.5	5.4	5.8	4.6	4.6	7.1
26.2	23.0	18.5	17.9	16.1	21.8	25.3	21.7
5.5	4.7	4.1	3.3	3.8	5.5	5.5	6.7
201	197	193	185	170	169	169	170
202	199	194	191	170	168	169	169
2,687	2,657	2,505	2,563	2,573	2,656	2,363	2,679
807	802	802	801	801	800	800	800
4,887	4,885	4,778	4,777	4,966	5,090	5,016	3,676
1,953	1,933	2,444	2,499	1,333	1,108	1,054	1,464
315	315	313	245	44	–	–	–
7,962	7,935	8,337	8,322	7,144	6,998	6,870	5,940
48,213	51,810	54,560	53,134	46,877	44,136	40,644	37,771

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

Return on capital employed = (comparable earnings before tax or earnings before non-controlling interests + income taxes + net interest expense) / average annual invested capital excluding AOCI

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

Dividend payout ratio = common share dividends / net earnings excluding gain on discontinued operations or comparable earnings

EBITDA = operating income + accretion + depreciation and amortization per the Consolidated Statements of Cash Flows

Dividend yield = common share dividends / current year's close price

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

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + net interest expense) / (interest on long-term debt–interest income)

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

SHAREHOLDER INFORMATION

Annual Meeting

The annual meeting will be held at 11:00 a.m. MST on Thursday, April 29, 2010, at the Hyatt Regency Hotel, 700 Centre Street S.E., Calgary, Alberta.

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Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares:

TSX: TA
NYSE: TAC

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:
Investor Relations
TransAlta Corporation
P.O. Box 1900, Station "M"
110–12th Avenue S.W.
Calgary, Alberta T2P 2M1

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Calgary/outside North America:
403.267.2520

E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

Special Services for Registered Shareholders

Service	Description
Dividend reinvestment and share purchase plan*	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.
** Also available to non-registered shareholders.*

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split[1]
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.

1 *The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988, share split.*

Dividend Declaration

Dividends are paid quarterly as determined by the Board. In determining the level of the dividend, the Board assesses the dividend payout as a percentage of earnings and as a percentage of cash flow from operations over a period of time. The Board continues to focus on building sustainable earnings, cash flow, and dividend growth and has adopted a formal dividend policy that targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings.

Important Dividend Dates

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2009	March 1, 2009	Feb. 25, 2009	$0.29
July 1, 2009	June 1, 2009	May 28, 2009	$0.29
Oct. 1, 2009	Sept. 1, 2009	Aug. 28, 2009	$0.29
Jan. 1, 2010	Dec. 1, 2009	Nov. 27, 2009	$0.29
April 1, 2010	March 1, 2010	Feb. 24, 2010	$0.29

Dividends are paid on the first of the month in January, April, July, and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

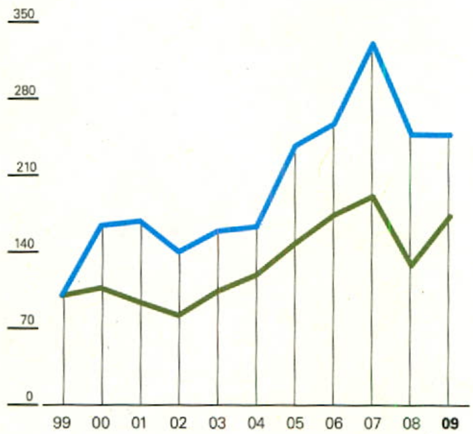
Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders, or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Vice-President and Corporate Secretary of the Corporation.

SHAREHOLDER HIGHLIGHTS

Total Shareholder Return vs. S&P/TSX Composite Total Return Index

Year Ended Dec. 31 ($)



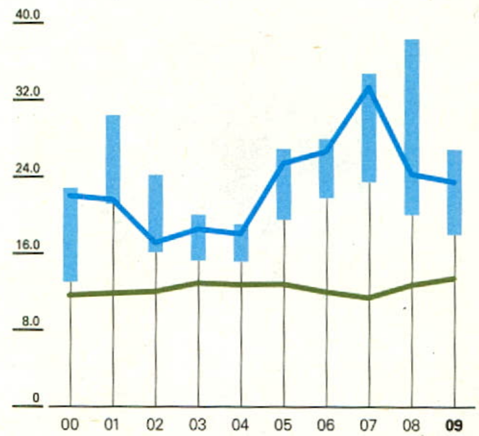
	99	00	01	02	03	04	05	06	07	08	09
TRANSALTA	100	164	168	140	159	163	237	257	330	247	247
S&P/TSX COMPOSITE INDEX	100	107	94	82	104	119	148	174	191	128	173

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 1998 would be worth today, assuming the reinvestment of all dividends.

Source: Thompson Financial

Ten-Year Trading Range and Market Value vs. Book Value

($ per share)



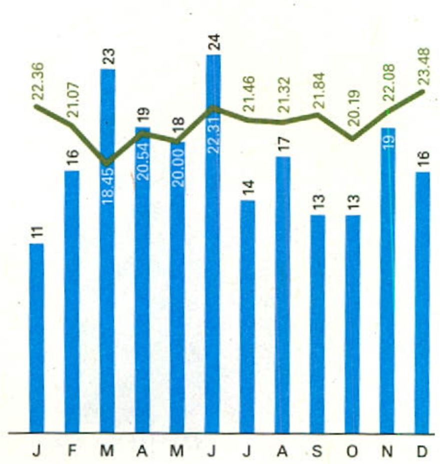
	00	01	02	03	04	05	06	07	08	09
MARKET VALUE	22.00	21.60	17.11	18.53	18.05	25.41	26.64	33.35	24.30	23.48
BOOK VALUE	11.61	11.82	12.01	12.90	12.74	12.80	11.99	11.39	12.70	13.41

TRADING RANGE

Source: Thompson Financial and TransAlta (MD&A)

Monthly Volume and Market Price

(2009)



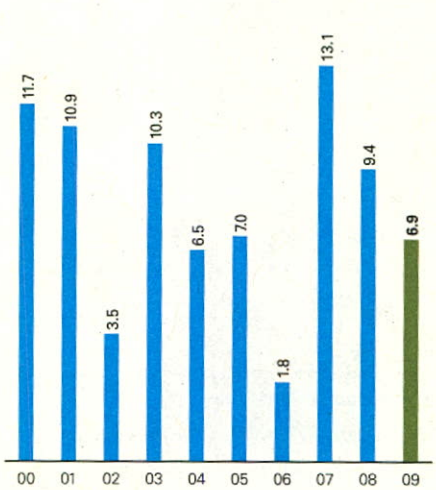
Volume (millions of shares)

TSX closing market price on last day of the month ($ per share)

Source: Thompson Financial

Return on Common Shareholders' Equity

(%)



Source: TransAlta (MD&A)

CORPORATE INFORMATION

TransAlta Corporate Officers

Stephen G. Snyder
President & Chief Executive Officer

Dawn Farrell
Chief Operating Officer

William D.A. Bridge
Chief Technology Officer

Brian Burden
Chief Financial Officer

Ken Stickland
Chief Legal Officer

Michael Williams
Chief Administration Officer

Frank Hawkins
Vice-President & Treasurer

Hume Kyle
Vice-President, Finance & Controller

Maryse St.-Laurent
Vice-President & Corporate Secretary

TransAlta Subsidiaries

Lou Florence
President, TransAlta Centralia Generation & Mining LLC

Aron Willis
Country Manager, TransAlta Energy (Australia) Pty Ltd.

Corporate Governance

TransAlta's Corporate Governance Guidelines; Board Charter; Committee Charters; position descriptions for the Chair, Committee Chair, President & CEO; and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Ethics Help-Line

The Audit and Risk Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors, shareholders, and other stakeholders to call with respect to accounting irregularities, ethical violations, or any other matters they wish to bring to the attention of the Board. The Ethics Help-Line number is 1.888.806.6646.

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

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Air Emissions Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury and greenhouse gases.

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

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

Boiler A device for generating steam for power, processing or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Brownfield Asset A previously constructed electric power generating facility.

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

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

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.

CO_2 Emissions Intensity Amount of carbon dioxide emitted per MWh produced.

Coal Gasification The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen or a variety of other chemical products.

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.

Combined Cycle An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

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

Expected Capability Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

Flue Gas Desulphurization Unit (Scrubber) Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure Literally means "greater force". These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigajoule (GJ) A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 BTU.

Gigawatt (GW) 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.

Greenfield Asset A new electric power generating facility built from the ground up on a new site.

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.

Merchant Asset TransAlta uses the term merchant to describe assets that have contracts with terms less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short- and medium-term contracts.

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.

Peaker Plant A plant usually housing low-efficiency steam units, gas turbines, diesels or pumped-storage hydro-electric equipment normally used during peakload periods.

Renewable Power Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

Reserve Margin An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Run Rate The result of extrapolating financial data collected from a period of time less than one year to a full year.

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

Supercritical Technology The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house and low nitrogen oxide burners.

Target Zero TransAlta's initiative designed to drive health, safety and environmental performance to zero lost-time, medical aid and environmental incidents.

Turbine A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

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.

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