
TransAlta
2007
ANNUAL
REPORT
we're ready
for a changing world

It’s obvious…the world is changing.

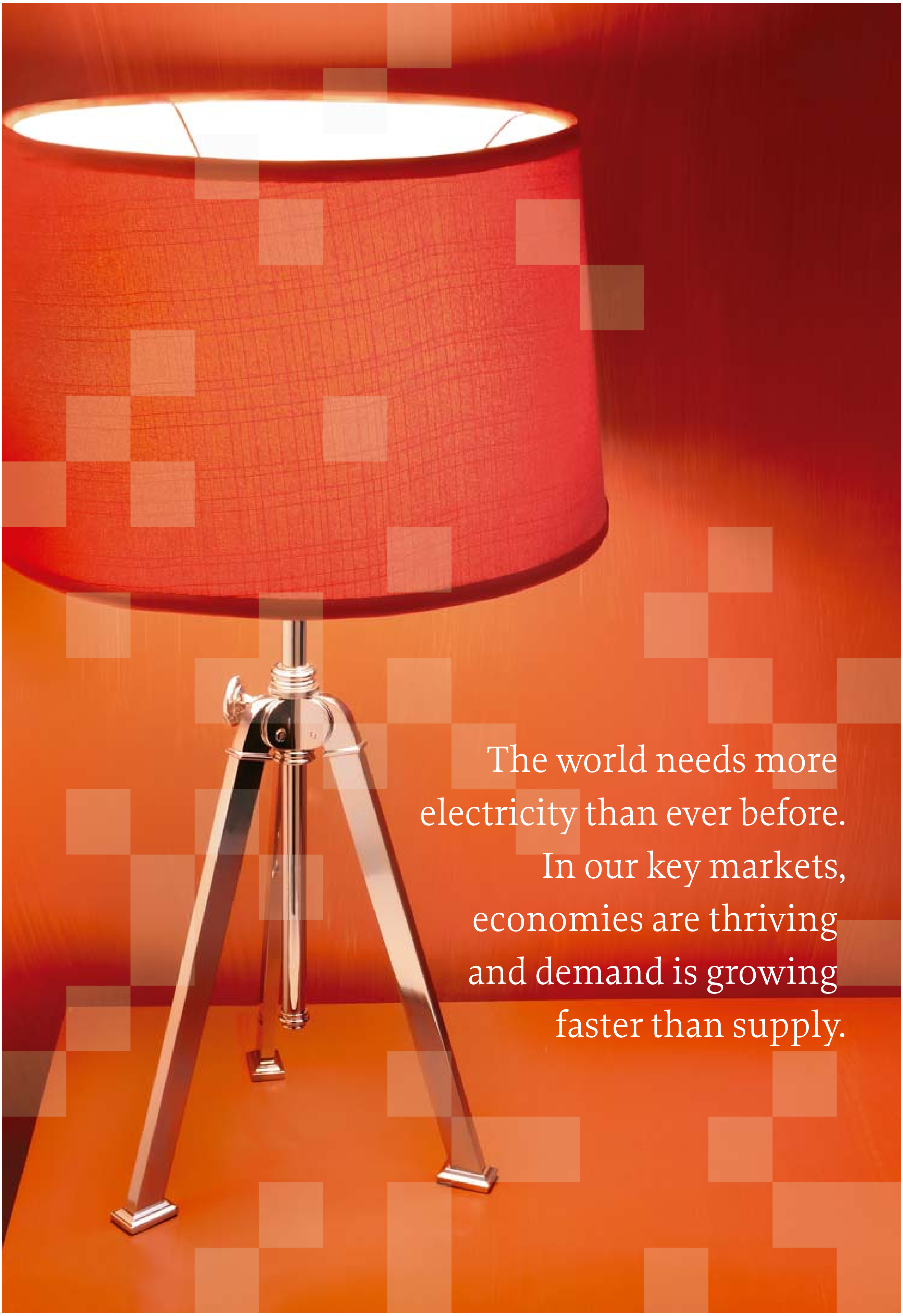
we’re ready.

As one of western North America’s leading power generation companies, TransAlta is uniquely positioned to take on the challenges of our changing times.

- We have a highly diversified portfolio of generation assets – primarily located in western North America – with a variety of fuel types including renewables.
- Our fuel diversity provides strong ongoing potential – hydro, wind, geothermal, natural gas and coal.
- We maintain a low- to moderate-risk business model, driven by our investment grade balance sheet and long-term contracts.
- Our asset base can be continuously renewed for the long-term sustainability of the Company through efficient investments. This strength is reflected in the strong cash flow we generate and our balanced approach to capital allocation.
- We consistently take a long-term view, keeping our focus on operations, costs and productivity, and sustaining a strong balance sheet. These fundamental keys to success are as true today as they were in the past.

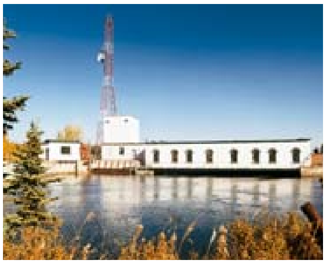
Looking ahead, we see exciting market opportunities, and we have a sound strategy to deliver consistent and growing shareholder value.

We’re ready…


The world needs more
electricity than ever before.
In our key markets,
economies are thriving
and demand is growing
faster than supply.

we're ready…

to meet the growing needs of our customers.

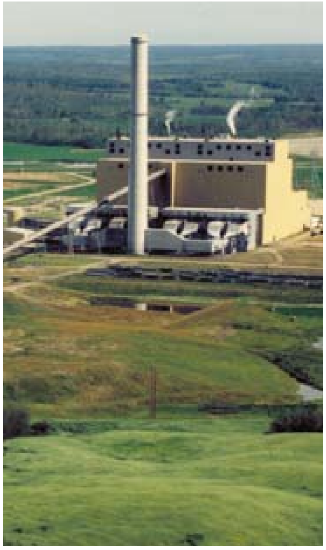


Our customers know they can depend on us to supply their steadily growing demand for electricity.

We're well positioned to meet their needs for reliable, competitively priced electricity.

We keep TransAlta's existing assets in optimal condition to ensure they're available to supply our customers' critical electricity needs when called on. And, as key markets like Alberta grow, we're adding much-needed new supply – "uprating" or retrofitting our existing plants and constructing new renewable, cogeneration, and thermal assets.

Our goal is to build on our strengths to become a super-regional, western wholesale power generation company.



Clockwise from top:
McBride Lake Wind Farm, Kananaskis Dam, Keephills Plant

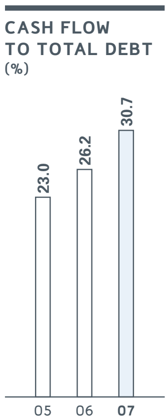

Global financial markets are
volatile. A successful company
must have the financial strength
and flexibility to build value
through all market cycles.

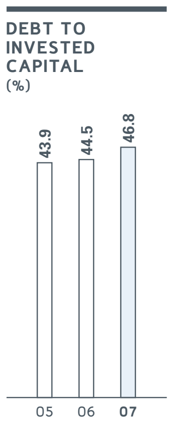
Electricity is a long-cycle, capital-intensive industry.

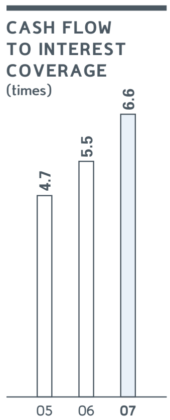
With a strong balance sheet and financial flexibility, TransAlta is ready and able to weather financial turbulence and commodity cycles.

Our financial strength enables us to contract our assets for better and longer terms, and provides us with the necessary access to Canadian and U.S. capital markets at all times. It also gives us an edge in capitalizing on opportunities as they arise.

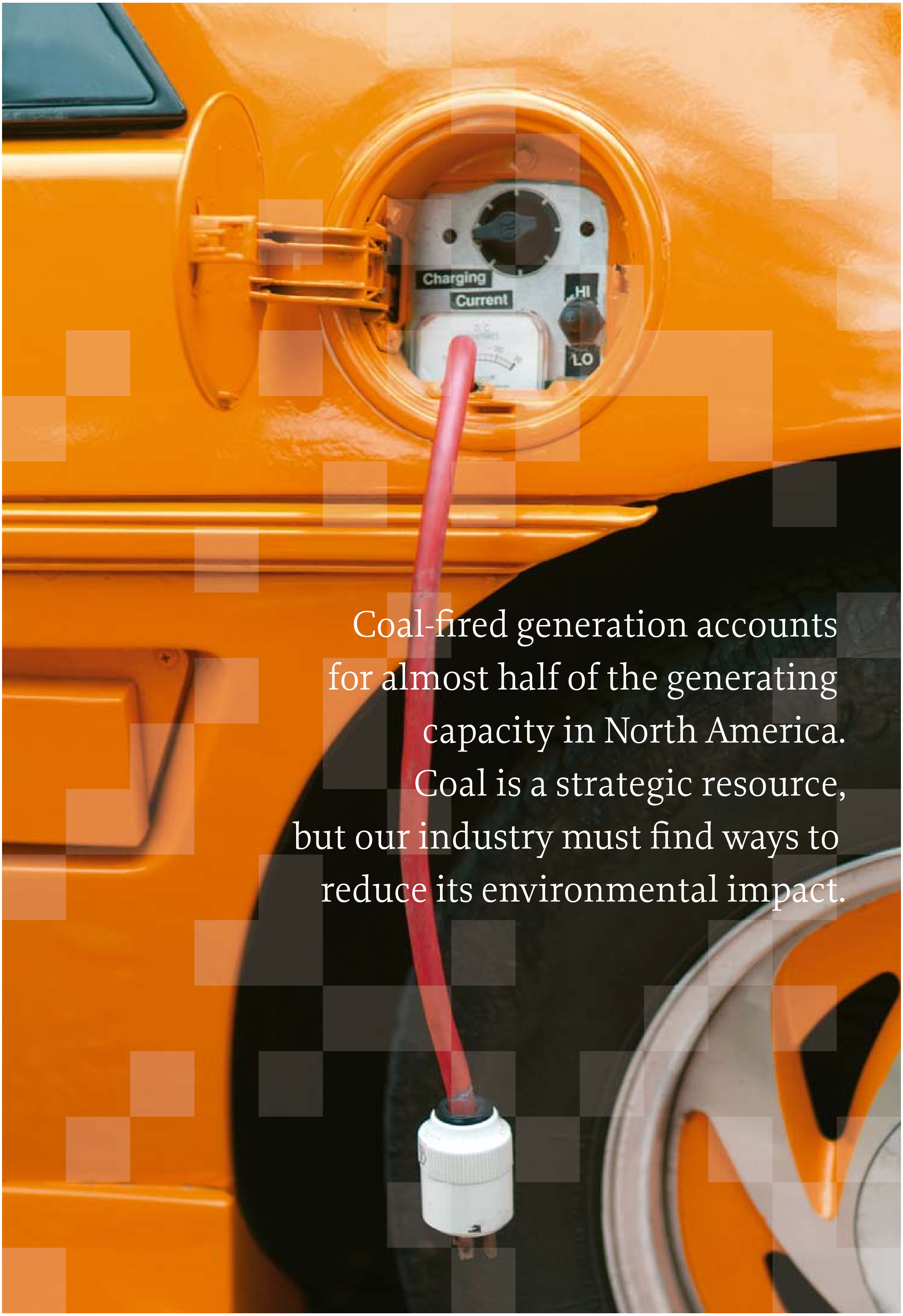
Our goal is to continue to strike the right balance between dividends, share buybacks, and growth investments to deliver consistent, sustainable value to our shareowners.







Above: *Centralia Thermal Plant*



Coal-fired generation accounts for almost half of the generating capacity in North America. Coal is a strategic resource, but our industry must find ways to reduce its environmental impact.

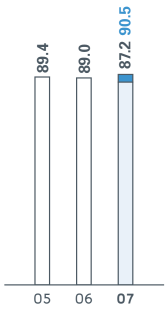
A number of advanced technologies are emerging for using coal as a cleaner fuel source.

New technologies, like carbon capture and storage, have the potential to reduce many of our environmental challenges. Once commercially viable, they'll play a critical role in the retrofitting of TransAlta's thermal generation facilities.

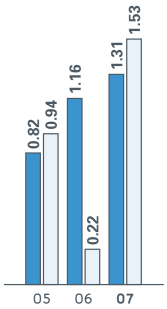
Carbon capture is a technically viable, environmentally safe means of reducing greenhouse gasses, and is ideally suited for our thermal energy plants.

These emerging technologies give us an excellent opportunity to prolong the life cycle of our thermal plants and continue to run them and serve our customers. And what's good for the environment is also good for business.

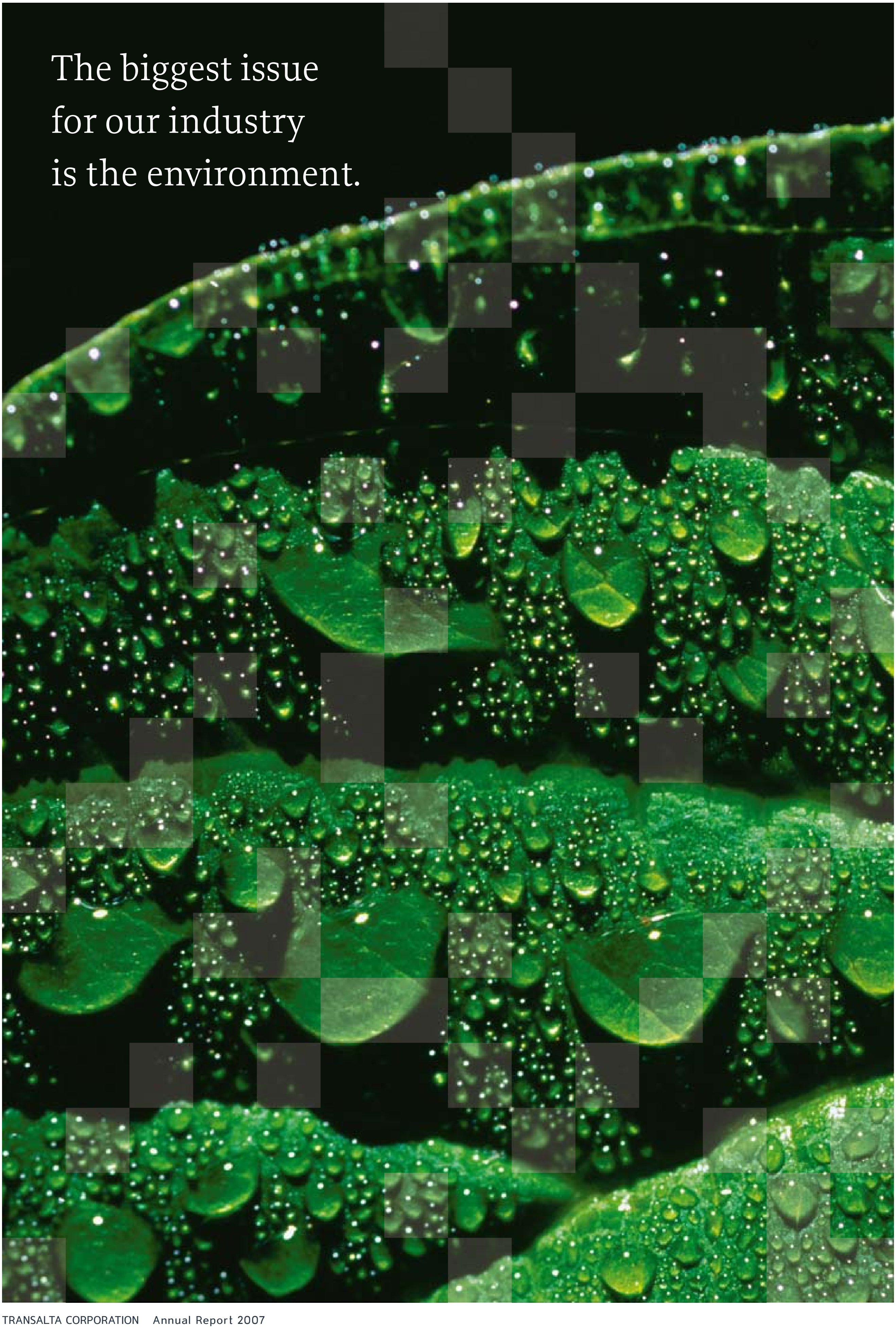
PLANT AVAILABILITY
(%)
■ adjusted for Centralia derates



EARNINGS PER SHARE
($)
■ comparable
□ reported



Above: *TransAlta employees are ready for the technological challenges ahead.*


The biggest issue
for our industry
is the environment.

We've been a sustainable development leader for over a decade and our efforts are producing results.

In the last few years we've reduced our sulphur dioxide intensity by 62 per cent and our nitrogen oxide intensity by seven per cent. We've also made significant strides in reducing mercury emissions. By testing new technology at our Sundance plant, we believe we'll be able to reduce our overall mercury emissions by another 70 per cent by 2010.

We have also taken steps to reduce our greenhouse gas emission intensity by improving the efficiency of our thermal plants and investing in alternative energy projects. Over the last decade, we've become Canada's leading provider of wind power generation and we continue to invest in this clean, renewable source of energy.

We've been recognized for our environmental leadership, with a listing on the North American Dow Jones Sustainability Index ("DJSI") and on the FTSE4Good global index. The Carbon Disclosure Project also selected us as one of 16 Canadian companies highlighted for proactively addressing the challenges posed by climate change.

Our goal is to continue to find ways to reduce our environmental footprint while delivering value to our shareowners.

reduced our sulphur dioxide intensity by **62%***

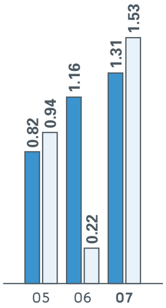
reduced our nitrogen oxide intensity by **7%***

* *based on best available data at time of report production.*

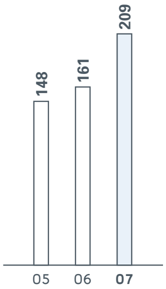
Above: *Sundance Plant*

Financial Highlights

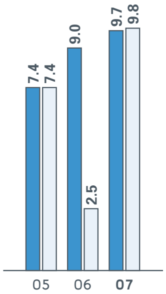
EARNINGS PER SHARE ($)
■ comparable
□ reported



TOTAL SHAREHOLDER RETURN
($) cumulative value of $100 investment assuming investment of dividend



RETURN ON CAPITAL EMPLOYED (%)
■ comparable ROCE
□ ROCE



IN MILLIONS OF CANADIAN DOLLARS
except per common share data and ratios

Year ended Dec. 31	2007	2006	2005
Revenues	$ 2,774.7	$ 2,677.6	$ 2,664.4
Net earnings	$ 308.8	$ 44.9	$ 186.3
Comparable earnings	$ 264.3	$ 233.8	$ 161.3
Cash flow from operations	$ 847.2	$ 489.6	$ 619.8
Per common share data			
Net earnings	$ 1.53	$ 0.22	$ 0.94
Comparable earnings	$ 1.31	$ 1.16	$ 0.82
Dividends	$ 1.00	$ 1.00	$ 1.00
Ratios			
Cash flow to interest coverage (times)	6.6	5.5	4.7
Cash flow to total debt (%)	30.7	26.2	23.0
Debt to invested capital (%)	46.8	44.5	43.9
Return on capital employed (%)	9.8	2.5	7.4
Comparable return on capital employed (%)	9.7	9.0	7.4

Message to Shareholders

STEVE SNYDER
President & CEO

TransAlta had a strong and productive year in 2007. Thanks to all of our employees, we achieved record results for our comparable earnings and for cash flow. Return on capital employed increased, total shareholder returns exceeded our target, and our balance sheet at the end of the year remained strong.

We were successful in keeping operating costs below the rate of inflation. We successfully implemented the first phase of our Centralia fuel transition plan. We advanced our growth strategy by completing the uprate on our Sundance Unit 4 and began work on both the Keephills 3 and Kent Hills projects. We accomplished all this while meeting our safety targets, and achieving our lowest employee injury frequency rate.

These accomplishments, along with steadily improving financial results and the potential for positive market conditions ahead, position TransAlta to deliver low double-digit earnings per share growth and strong cash flow in 2008 and the years ahead.

Building a Strategic Advantage

We are a wholesale power generation company with financial strength and flexibility focused on the growing western markets. Our Company has elements of a regulated entity, due to the nature of our long-term contracts, and also that of an independent power producer as we also have access to merchant markets. That makes us unique relative to most of our peers in the North American energy sector.

Approximately 70 per cent of our capacity is contracted under government-mandated power purchase agreements or long-term contracts. These contracts support our low- to

We are a wholesale power generation company with financial strength and flexibility focused on the growing western markets.

moderate-risk business profile and our capabilities to deliver steady, stable earnings and cash flow. They secure our commitment to growing total shareholder returns. Our modest merchant exposure provides market upside potential.

The soundness of this strategy has been seen in our performance over the last 10 years. That period was marked by challenging credit and commodity markets. Many independent power producers went bankrupt. At TransAlta, we not only retained our investment grade credit rating, we improved it, while maintaining our dividend.

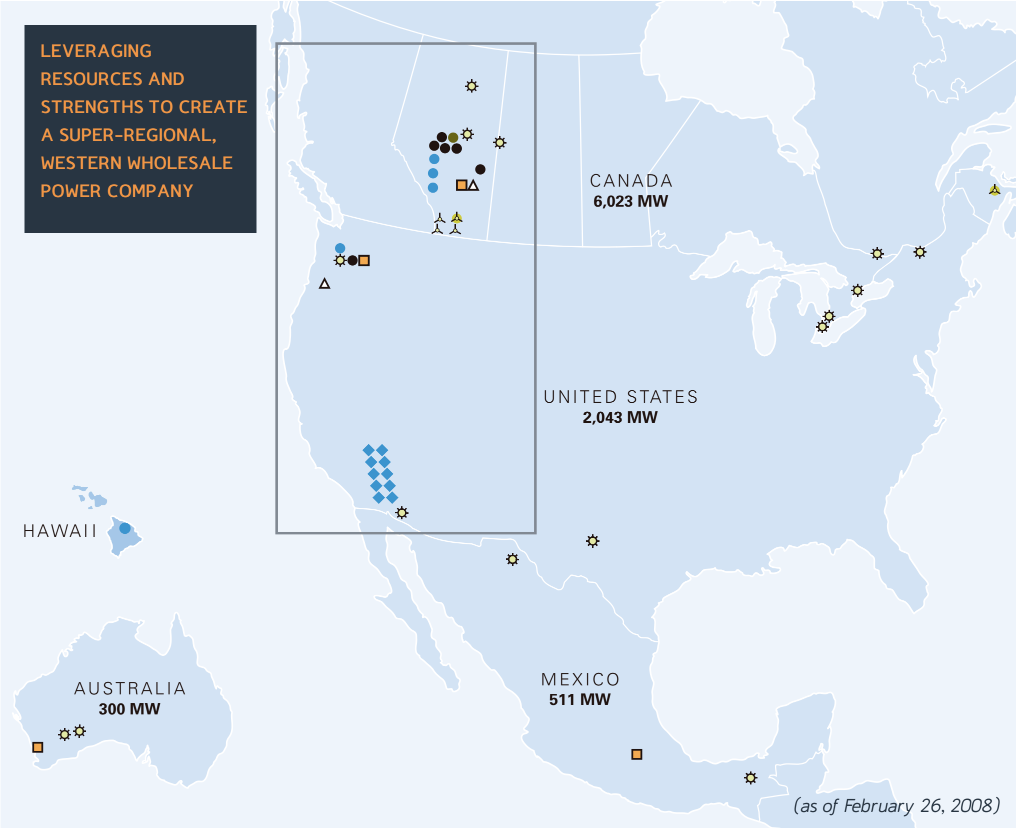
A strong balance sheet and investment grade credit rating benefit investors in a long-cycle, capital intensive, commodity-sensitive business. It improves our competitiveness by lowering our cost of capital compared to non-investment grade companies. It enables TransAlta to contract its assets with customers on more favourable terms. We prize financial flexibility, which allows us to access the capital markets at the lowest all-in cost of financing. This financial strategy has supported our strong total shareholder return over the last decade.

We have consistently paid a dividend. I believe the dividend is an important part of the value proposition we offer shareholders. In the last decade we have paid over $2 billion in dividends to shareholders. On February 7th, 2008, TransAlta's Board of Directors announced an increase in the annual dividend to $1.08 from $1.00. This eight per cent increase reflects our growing earnings, the confidence in our business, and our commitment to build sustainable earnings and dividend growth.

In addition to this steady dividend, our capital allocation decisions balance investment in new capacity, share repurchases, and opportunities to optimize the portfolio as we did early in 2008 with the sale of our Mexican business for $304 million. Growing economies in our markets have created some very attractive opportunities to create shareholder value by investing in additional capacity such as renewable energy and co-generation facilities. These new assets can deliver excellent returns and long-term, stable cash flow.

Share buyback is also part of our balanced capital allocation plan. In 2007, under our normal course issuer bid ("NCIB") we spent $75 million to purchase approximately 2.4 million shares. For 2008, as we look at our requirements for liquidity, the need to maintain our key financial ratios, and cash from the divestiture of our Mexican business, we expect to continue to repurchase shares in accordance with the TSX NCIB rules.

Our unique combination of resources and proven strengths differentiates our Company and positions it to fully capture the upside potential from today's buoyant electricity markets. Our legacy assets are profitable cash generators. We own long-term coal reserves, untapped hydro resources, optioned wind development sites, reservoirs for CO_2 storage, and highly sought brownfield sites with connectivity to transmission. We have access to water and



GENERATION FACILITIES	CAPACITY OWNED
Coal-fired plants	4,942 MW
Coal-fired plant (IN DEVELOPMENT)	225 MW
Hydro plants	807 MW
Gas-fired plants	2,470 MW
Wind-powered plants	154 MW
Wind-powered plant (IN DEVELOPMENT)	162 MW
Geothermal plants	164 MW
Corporate offices	
Energy Marketing offices	

On Feb. 20, 2008, TransAlta announced the sale of its Mexican business (511 MW gas-fired plants). The sale is still subject to regulatory approval. For a more detailed breakdown of our assets, please turn to page 26.

multiple fuels. All provide TransAlta with a multitude of development options to profitably expand our portfolio, meet growing power demand, and create value for shareowners.

In addition, we have the skills required to achieve top decile operations at our plants and mines, build out our fleet, navigate and influence regulatory and environmental challenges, and optimize our portfolio to capture near-term upside and protect shareowners from increasing price volatility.

Ready for Change

The environment we operate in is changing.

Simply put, our industry must struggle to break the current "triple E" equation: energy growth = economic growth = environmental problems. It's hard to grow the economy and the standard of living competitively without using more energy, and it's hard to use more energy and not impact the environment.

Longer-term, the industry is facing one of the most profound technological shifts in its history. This change is driven by the need to reduce the power industry's environmental footprint, particularly the production of greenhouse gases. Consequently, we are going to have to implement new technologies that can cost-effectively reduce our emissions and still allow our plants, especially our thermal-fueled facilities, to be competitive. That's a tough challenge.

But we saw this shift coming many years ago and have been preparing for it.

We have been a leader in developing renewable power and the purchase of emission offsets. Both initiatives will help us to bridge the transition until full-scale carbon capture

Simply put, our industry must struggle to break the current "triple E" equation: energy growth = economic growth = environmental problems.

MANAGEMENT TEAM (left to right)
Richard Langhammer, Executive Vice-President, Generation Operations; Ken Stickland, Executive Vice-President, Legal; Will Bridge, Executive Vice-President, Generation Technology & Procurement & Material Management; Steve Snyder, President & Chief Executive Officer; Dawn Farrell, Executive Vice-President, Commercial Operations & Development; Mike Williams, Executive Vice-President, Human Resources, Information Technology & Communications; Brian Burden, Executive Vice-President & Chief Financial Officer

technology can be developed and commercialized. We also continuously invest in our plants to improve efficiency and increase productivity – which also minimizes emissions. Over the last several years, we have put in place a rigorous asset-planning process to predict the optimal timing of investments in our fleet.

We are working with policy-makers to develop an economic framework to provide incentives for investment in CO_2 capture and sequestration. As we transition to this new framework, the terms of our Alberta power purchase arrangements ("PPAs") allow us to recover the costs related to legislated changes that affect our Alberta plants.

We are also partnering with key equipment manufacturers to obtain the necessary incentives and support to build a pilot project on a TransAlta site. By selecting the technology that will allow us to meet the most exacting environmental standards while delivering the lowest-cost electricity to our customers, we can continue to grow earnings after the Alberta PPAs expire.

TransAlta, like our industry, is at a key juncture in its history. Ahead of us are the best growth opportunities and market conditions we have seen.

In 2007 we continued our progress in evaluating ways to cost-effectively run our thermal plants for life cycles beyond 40 years while meeting the toughest environmental standards. This has the potential to create the greatest value for the Company in the coming years. Our high-level estimates today show a compelling advantage in prolonging our thermal plants' life cycle relative to building a new plant.

Between 2008 and 2009, we will conduct detailed engineering assessments on each of our units to determine more precisely what technical changes are required to operate these assets for an additional 10–20 years. We'll also continue to work toward finding the right CO_2 capture technology. This won't be easy, but the potential payoff for our shareowners will be compelling if the all-in cost of investing in our current fleet proves to be superior to building new plants.

There is an urgent need for new power capacity in many of our markets. Reserve margins are nearing or are already below 15 per cent. That's an industry warning signal for decreased reliability of supply, and it creates opportunities for new investments in North America. I believe these investment opportunities have returns that are now better than what we could only find internationally in years past. To take advantage of these conditions, we'll focus our development efforts on western North America. Our goal is to build on our strength as a super-regional, western wholesale power competitor.

To succeed in this effort, we'll have to navigate through some tough impediments – transmission constraints, rising component costs, and equipment and labour shortages. But, with nearly 100 years of operating experience behind us, I believe we'll be successful. In the recent past, we have developed key long-term strategic supplier relationships with industry leaders to help secure materials and services when needed and at more predictable prices.

We'll also invest in technologies where we have proven competencies and enjoy a competitive edge: wind, natural gas co-generation, geothermal, and small-scale hydro. We are currently considering approximately 1,000 megawatt ("MW") of project opportunities in these segments.

A decade ago, our industry believed it would move to a deregulated wholesale power model. This has not happened. The U.S. in particular is now a patchwork of traditional rate-of-return-based power companies and others with hybrid elements of both market-based and traditional regulation. Recognizing that reality, and consistent with our growth objective and retaining a low-to-moderate risk profile, we must now consider opportunities to acquire regulated assets. These efforts will be focused on the western North American markets as we build an even stronger competitive position.

TransAlta, like our industry, is at a key juncture in its history. Ahead of us are the best growth opportunities and market conditions we have seen. But there are also challenges – including environmental challenges, technological change, an increasing trend to more regulatory oversight, transmission constraints, and considerable cost uncertainties around alternate fuel sources. With a strong balance sheet and a disciplined and balanced approach to capital allocation, we are well positioned to capitalize on the market potential and deliver excellent shareholder returns, while meeting these challenges head on.

All these efforts are supported by our superb team of employees. Time after time they have demonstrated resiliency, an ability to rise to challenges, a focus on shareowner value, and an unwavering dedication to excellence. Their skills, combined with the contribution of our worldwide suppliers and our commitment to our customers, ensures we can deliver on the opportunities ahead of us. I want to sincerely thank our employees, our suppliers, and our customers for their role in our mutual success.

Change is coming, and we're ready. As always, thank you for your support.

Sincerely,

STEVE SNYDER
President & Chief Executive Officer
February 26, 2008

A strong balance sheet and investment grade credit rating benefit investors in a long-cycle, capital intensive, commodity-sensitive business.

Performance Metrics for a Changing World

Availability and 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. Our goal is to achieve top decile availability in the industry of 92 per cent.

Production is also a significant driver of revenue in certain contracts. Production is the amount of electricity generated and is measured in gigawatt hours ("GWh"). Our goal is to optimize production through planned maintenance programs, the use of monitoring programs to minimize unplanned outages and derates, and generate power from our plants when it is most economic.

	05	06	07	Target 08–10
Availability (%)	89.4	89.0	87.2	90–92
Production (GWh)	51,810	48,213	50,395	Optimize

Productivity

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

	05	06	07	Target 08–10
OM&A ($/installed MWh)	8.16	7.93	7.81	Offset inflation

Safety

Safety is a core value at TransAlta. We take it very seriously and measure ourselves against industry-wide standards. The Injury Frequency Rate ("IFR") measures all fatal, lost time and medical aid injuries. While our ultimate goal is to have zero injury incidents, we are aggressively targeting a 10 per cent reduction year over year in our IFR.

	05	06	07	Target 08–10
Injury Frequency Rate	1.41	1.96	1.76	Reduce >10% annually

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that needs consistent and stable capital expenditures. 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. Our goal is to make sustaining capital expenditures more predictable and in line with our long-range plans.

	05	06	07	Target 08–10
Sustaining Capex ($ millions)	287	207	371	290–325 [1]

1 Based on average yearly spend for 2008–2010

Earnings Per Share and Cash Flow

Comparable earnings per share ("EPS") is frequently used to measure a company's ongoing profitability. Our target is to generate low double-digit EPS growth on a comparable basis annually.

Cash generated from operations is used to maintain our equipment, meet our debt repayment obligations, return capital to shareowners through dividends and share buybacks, and invest in new capacity. Our goal is to generate cash from operations of $850–$950 million per year.

	05	06	07	Target 08–10
Earnings per share (comparable basis) ($)	0.82	1.16	1.31	Increase >10% annually
Cash from operations ($ millions)	620	490	847	850–950

Investment Ratios

Financial strength and flexibility are critical to the Company's ability to create value, capitalize on opportunities and manage industry cyclicality. Our goal is to maintain investment grade credit ratings and operate the business within established financial ratio ranges. These ratios include: cash flow to interest, cash flow to total debt, and debt to invested capital. Credit rating agencies use these ratios when evaluating the financial strength of the Company.

	05	06	07	Target Range
Cash flow to interest (times)	4.7	5.5	6.6	Minimum of 4
Cash flow to total debt (%)	23.0	26.2	30.7	Minimum of 25
Debt to invested capital (%)	43.9	44.5	46.8	Maximum of 55

Sustainable Long-Term Shareholder Value

We measure returns to our shareholders and investors in two ways: comparable return on capital employed ("Comparable ROCE") and total shareholder return ("TSR"). Comparable ROCE measures the economic value created from capital investments. TSR is the total amount returned to investors over a specific holding period and includes capital gains and dividends. Our goal is to achieve greater than 10 per cent for both ROCE and TSR.

	05	06	07	Target 08–10
Comparable ROCE (%)	7.4	9.0	9.7	>10 annually
TSR (%)	47.6	9.2	29.0	>10 annually

Sustainable Development

Committed to a Sustainable Future

At TransAlta, we see sustainability as a responsible and pro-active balancing of careful growth, environmental stewardship, and positive and rewarding relationships with our employees and the communities near our operations. This approach has positioned the Company as a leader in sustainable development, a responsibility we take very seriously.

We have established a pattern of taking action and testing solutions ahead of regulation. Examples include mercury reduction testing at our Alberta plants, early and sustained greenhouse gas emissions trading and developing markets for fly-ash, a by-product of coal combustion.

By voluntarily leading the way, we can share what we learn with policy-makers and the rest of industry, typically resulting in more workable and practical answers. TransAlta is a trusted industry advisor to governments and is involved in emerging regulations across all of our jurisdictions.

Dow Jones Sustainability Indexes
Member 2007/08

Economic Sustainability

During 2007, the Governments of Canada, Alberta, Ontario, and Washington state each released their environmental plans to tackle air emissions. TransAlta is working with all governments to encourage broad, uniform initiatives. We believe a consistent approach will further environmental achievements and better support communities and economic growth.

The rapidly evolving regulatory framework has resulted in closer scrutiny of how companies manage environmental risk. TransAlta's continued investment grade rating is one indicator of how the market evaluates our sustainability efforts.

TransAlta's total shareholder return in 2007 was 29 per cent. Comparable earnings were up 13 per cent at $1.31 per share compared to $1.16 per share in 2006. Cash flow increased to $847 million in 2007. We use this cash to maintain our plants, pay down debt, return capital to shareholders through dividends and share buybacks, and reinvest in new assets. Over the last 10 years TransAlta has delivered 140 per cent cumulative total shareholder return; including more than two billion dollars in dividends.

Environmental Sustainability

Our emissions reduction strategy encompasses: investigating emission reduction technologies and improving fuel usage; technology retrofits for older facilities or in building new plants; offsets purchasing; and growing our renewables portfolio.

Air emissions associated with generating electricity are a key environmental issue. We have continually decreased our greenhouse gas emissions intensity since 2000, and have been leading a major mercury emission reduction project for the purpose of decreasing our mercury emissions in Alberta by 70 per cent by 2010. TransAlta's nitrous dioxide and nitrous oxide emission intensities have also decreased steadily since 2000. We will continue to aggressively pursue technologies and operational improvements, knowing that we are leading change in our industry.

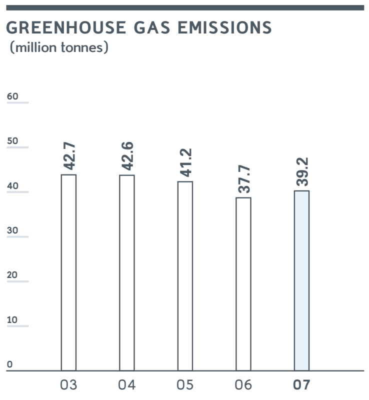
For the last two years, we have examined a number of options for low carbon power generation. While we believe that the responsible approach is to continue to investigate alternative or complementary solutions, we know that we are, and will continue to be, primarily a thermal power provider. The challenge is to keep it viable and socially acceptable.

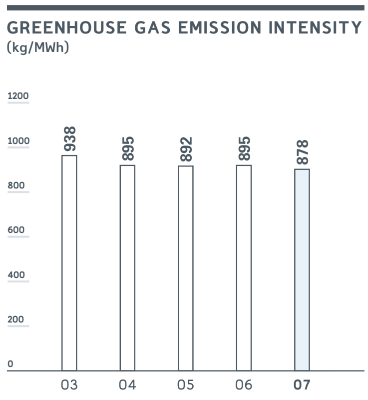
We believe carbon capture and sequestration is a significant part of the solution. Our intent is to prove the possibilities of carbon capture in Alberta in conjunction with other industry members and government.

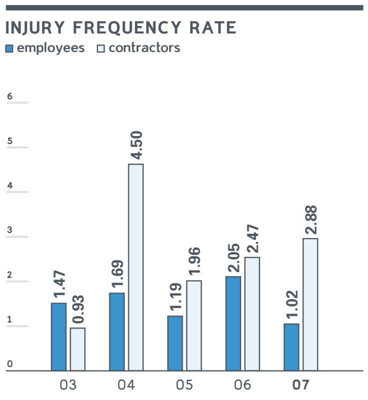
Social Sustainability – Workplace Safety and Community Relations

TransAlta's Environment, Health, and Safety management system ensures that our safety processes continually improve and that performance is communicated to the Board level. Our long-standing environment, health and safety program, Target Zero, guides the organization toward our goal of zero safety incidents.

In 2007, we succeeded in improving employee safety performance by 50 per cent, achieving our best safety record ever. We believe this success has been achieved through increased management commitment and intervention and through implementing rigorous safety programs, inspections and audits at all of our facilities. However, our contractor injury frequency rate increased by 17 per cent. This is a significant







2007 data are estimates based on best available data at time of report production. For more detail, refer to the 2007 Report on Sustainability.
Total GHG emissions increased from 2006 to 2007 due largely to higher plant availability.

concern for us as it is our goal to keep all of our employees and contractors safe while on our sites. Contractor safety management is a major focus area as we move forward.

Labour issues continued to be a challenge in 2007, along with an aging workforce. We will continue to address both of these issues with new strategies for recruitment, succession planning, and rotational job placement to keep our people challenged and engaged.

Public consultation is an integral part of our business, as we strive to minimize our impacts. A stakeholder relations strategy was developed at our Alberta Thermal operations in 2007, formalizing processes at the heart of our operations. In New Brunswick, stakeholder consultation for our newest wind farm, Kent Hills, was instrumental in educating the public and regulators who had never been exposed to wind generation, and resulted in permits being issued in a very short nine months.

Our involvement with Aboriginal communities near our operations continued with funding of elder programming, scholarship programs and targeted community involvement. We built upon our relationship with the Paul Band near our Alberta Thermal operations with the funding of a liaison position. We also made considerable progress in providing awareness to many First Nations of our transmission business through a Transmission Advisory Committee.

Community investment continues to be a key part of our commitment to sustainable communities around our operations. Details on our involvement in 2007 are described on the following page.

Looking Ahead

We are pursuing organic growth opportunities in the western U.S. and Canada with the goal of establishing a super-regional, wholesale generation company. We will focus on increasing our renewables portfolio, and in the short-term pursue wind, natural gas co-generation, geothermal, and small-scale hydro opportunities. Our early involvement in offsets trading has become a competitive advantage.

TransAlta's 2007 Report on Sustainability will be released in June 2008 at www.transalta.com.

Connecting with Communities

At TransAlta, strengthening communities where our employees live and work is a commitment we take seriously. Investing over $5 million in the focus areas of arts and culture, environment, education, and health and human services, as well as employee and retiree volunteer time, exemplifies this commitment.

Building on our sustainable business practices, we committed $1.25 million to create the TransAlta Professor of Environmental Management and Sustainability at the Institute of Sustainable Energy, Environment and Economy ("ISEEE") at the University of Calgary. Former TransAlta Vice-President Sustainable Development Dr. Bob Page leads innovative research, education, and outreach as part of this important initiative.

We extended our relationships with existing partners and made significant new investments, including a $600,000 donation to the Fast Track early childhood intervention program at Hull Child and Family Services. This school-based program focuses on changing school cultures and individual behaviours, while creating additional opportunities for youth and families. We also provided significant support to The Young Canadians School of Performing Arts through the Calgary Stampede Foundation, providing continued high-quality training and year-round program opportunities for students. We also furthered our investment in the TransAlta Tri-Leisure Centre, a multi-use community health and wellness facility located near our Alberta Thermal operations.

Our employees and retirees are actively engaged in their communities. When communities near our Centralia, Washington operations experienced severe flooding, TransAlta dispatched teams of employees to support rescue and relief efforts. In less than 11 days, these employees contributed 2,000 hours to the community along with financial and in-kind donations. The Company further responded by contributing heavy equipment, warehousing and distribution expertise, in addition to $50,000 in financial support.

Thanks to employee and retiree commitment to the United Way, TransAlta's United Way campaign achieved a new record of over $1.3 million, including a dollar-for-dollar corporate match. Employees contributed about 14,400 hours to the community, through volunteer projects like painting seniors' homes, a youth camp cleanup, food bank drives, building a school playground and Days of Caring. Senior executives led by example, providing expertise to community organizations through the Company's Executive Connections program.

PROUD PARTNER OF ALBERTA'S PROMISE
www.albertaspromise.org

Imagine Caring Company Une entreprise généreuse

TRANSALTA'S INVESTMENT in the ISEEE at the University of Calgary is part of our $5 million commitment to communities where our employees live and work.

Message from the Chair

DONNA SOBLE KAUFMAN
Chair of the Board

In 2007, TransAlta continued to execute on its plan and deliver value to our shareowners. It was a good year for your Company and we are pleased to report record results in several key areas. This reflects our continued focus on consistent, long-term value for our shareowners. I believe it also reflects the hard work and dedication of TransAlta's employees.

Our industry is experiencing a period of unprecedented change. We are seeing increasing financial turbulence, varying commodity cycles and fundamental shifts in environmental legislation and regulatory frameworks.

Your Company is Ready

We are ready to weather this change because we have continued to focus on maintaining our strong balance sheet while striking an effective balance between dividend growth, share buybacks, and capital investment. We also have a strategy fully supported by your Board to continue to create shareowner value, by capitalizing on TransAlta's resources and proven skills to become a super-regional, wholesale power company.

TransAlta is ready because we have continued to invest in new and innovative technologies, and we have continued to champion sustainable development. We are proud that leading organizations like the Carbon Disclosure Project have recognized our efforts. In 2007, it selected TransAlta as one of 16 Canadian companies highlighted for proactively addressing the challenges posed by climate change. It ranked TransAlta third of 200 in a survey of Canada's largest companies.

Finally, our commitment to an ethical culture and strong corporate governance provides us with a solid foundation to operate from, which is critically important in the face of increasing change and industry-wide instability. On this front, TransAlta is not only keeping pace with Canada's rising governance standards, we are continuing to lead the way. For example, in the area of compensation we have been recognized by the *Globe & Mail* newspaper for being among the first to adopt share ownership instead of options as the most responsible manner to align management incentives with shareowner interests. And, for the sixth consecutive year, the newspaper recognized TransAlta as one of the best-governed corporations in Canada, and the top company in the utilities sector for corporate governance. In the past, we've also been awarded an AAA rating for corporate governance from the Clarkson Centre for Business Ethics and Board Effectiveness.

Your Company is recognized for having a highly independent Board of Directors with an effective combination of skill and expertise. Our directors have broad experience in the energy industry, finance, risk management, operations, law and current oversight practices. This knowledge base, together with the expertise of our management team, has resulted in the structures and processes that provide the transparency our investors expect.

In the years to come, we will continue to make investments in sustainability and focus on governance initiatives, not just because it is the "right" thing to do, but because it makes good business sense. Over the past several years, this has become a consistent theme in Board discussions with our management team. Building a sustainable company that continually drives toward long-term growth for our share-owners is inherent in our governance model.

Our commitment to our shareowners is to deliver a strong, sustainable yield with a low-to-moderate risk profile. Along with our management team, we have always taken a long-term approach to our business. We recognize that you, our shareowners, entrust this duty to us and we are determined to continue to earn that trust.

After a record year in 2007, we have turned our attention to 2008 and beyond, with your interests foremost in our minds.

Thank you for placing your confidence in us.

Donna Kaufman

DONNA SOBLE KAUFMAN
Chair of the Board
February 26, 2008

BOARD OF DIRECTORS

(left to right)
Gordon Giffin,
Kent Jespersen,
Luis Vázquez Senties,
Tim Faithfull,
Martha Piper,
Steve Snyder,
Stanley Bright,
Donna Soble Kaufman,
Bill Anderson,
Michael Kanovsky,
Gordon Lackenbauer

WILLIAM D. ANDERSON *Corporate Director* Mr. Anderson was President of BCE Ventures (a subsidiary of BCE Inc.) from 2005 and prior to that, the CFO of BCE Inc. and of Bell Cablemedia plc. As President of BCE Ventures he was responsible for a number of significant operating companies as well as being CEO of Bell Canada International Inc. In his CFO roles, Mr. Anderson was responsible for all financial operations of the respective companies and he executed numerous debt and equity financings, corporate acquisition and disposition transactions as well as corporate and operational restructurings.

Mr. Anderson is a director of Gildan Activewear Inc. and of MDS Inc. He is a past director at BCE Emergis Inc., Bell Cablemedia plc, Bell Canada International Inc., CGI Group Inc., Four Seasons Hotels Inc., Sears Canada Inc., and Videotron Holdings plc. At TransAlta, Mr. Anderson is Chair of the Audit and Risk Committee of the Board.

Mr. Anderson holds a bachelor's degree in business administration from the University of Western Ontario (London, ON), and is a Chartered Accountant.

STANLEY J. BRIGHT *Corporate Director* Mr. Bright was President, CEO, and Chairman of MidAmerican Energy Holdings Company from 1997 to 1999. He was also President, CEO, and Chairman, and CEO, of predecessor companies, including the Iowa-Illinois Gas & Electric Company ("IIG&E"), from 1991 to 1997. As the CEO of IIG&E, Mr. Bright led the consolidation of a number of Midwest utilities in anticipation of emerging market competition, giving rise to the creation of MidAmerican. As the President, CEO, and Chairman of the new entity, Mr. Bright led the realization of significant synergies while working through the post-merger transition. The company also structured a long-term rate plan with the Iowa Public Service Commission. Mr. Bright retired as CEO of MidAmerican in 1999 but continued as a director until 2006.

At TransAlta, Mr. Bright is Chair of the Human Resources Committee of the Board.

Mr. Bright holds a bachelor's degree in accounting from The George Washington University (Washington, DC), and is a Certified Public Accountant.

TIMOTHY W. FAITHFULL *Corporate Director* Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc, where he filled diverse roles that spanned the globe. As President and CEO of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line, the first fully integrated oil sands venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operation for the Shell International Trading and Shipping Company from 1993 to 1996.

Mr. Faithful is a director of Canadian Pacific Railway Limited, the Shell Pension Trust Limited, and AMEC plc. At TransAlta, Mr. Faithfull is a member of the Audit and Risk Committee and the Human Resources Committee of the Board.

Mr. Faithfull holds a bachelor's of arts degree in economics from the University of Oxford (Oxford, UK).

GORDON D. GIFFIN *Corporate Director, Lawyer and Senior Partner, McKenna, Long & Aldridge LLP.* From 1997 to 2001, Ambassador Giffin served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy. Prior to this appointment, he practiced law for 18 years as a senior partner in Atlanta, GA and Washington, DC. His practice focused on energy regulatory work at the state and federal level. He previously served as Chief Council and Legislative Director to U.S. Senator Sam Nunn, with responsibility to manage the legal and legislative operations of the office. In 2001, he returned to private practice where he specializes in state and federal regulatory matters, including those related to trade, energy and trans-border commerce.

He is a director of AbitibiBowater, Canadian Imperial Bank of Commerce, Canadian National Railway Company, Canadian Natural Resources Limited, and Ontario Energy Savings Ltd. At TransAlta, Ambassador Giffin is Chair of the Governance and Environment Committee of the Board.

Ambassador Giffin holds a bachelor of arts from Duke University (Durham, NC) and a juris doctorate from Emory University School of Law (Atlanta, GA).

C. KENT JESPERSEN *Corporate Director and Chair and CEO of LaJolla Resources International Ltd.* He also has held senior executive positions with NOVA Corporation of Alberta, Foothills Pipe Lines Ltd., and Husky Oil Limited before assuming the presidency of Foothills Pipe Lines Ltd. and later, NOVA Gas International Ltd. At NOVA, he led the non-regulated energy services business (including energy trading and marketing) and all international activities.

Mr. Jespersen is the Chairman and a director of Orvana Minerals Ltd. and CCR Technologies Ltd., and a director of Matrikon Inc. and of Axia NetMedia Corporation. At TransAlta, Mr. Jespersen is a member of the Governance and Environment Committee and the Human Resources Committee of the Board.

Mr. Jespersen holds a bachelor of science in education and a master of science in education from the University of Oregon (Eugene, OR).

MICHAEL M. KANOVSKY *Corporate Director and Independent Businessman* He co-founded Northstar Energy with initial capital of $400,000 and helped build this entity into an oil and gas producer that was sold to Devon Energy for approximately $600 million in 1998. During this period, Mr. Kanovsky was responsible for strategy and finance, as well as merger and acquisition activity. He initiated Northstar's entry into electrical co-generation through its wholly owned power subsidiary, Powerlink Corporation. Powerlink developed one of the first independent power producer ("IPP") gas-fired co-generation plants in Ontario and also internationally. In 1997, he founded Bonavista Energy, which has grown to a present-day market cap of approximately $6 billion.

Mr. Kanovsky is a director of Accrete Energy Corporation, ARC Energy Trust, Devon Energy Corporation, Bonavista Energy Trust, and Pure Technologies Inc. At TransAlta, he is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board.

Mr. Kanovsky, a professional engineer, holds a bachelor of science in mechanical engineering from Queen's University (Kingston, ON) as well as a master of business administration from the Ivey School of Business at the University of Western Ontario (London, ON).

DONNA SOBLE KAUFMAN *Lawyer and Corporate Director* Mrs. Kaufman is a former partner with Stikeman Elliott, an international law firm, where she practiced antitrust law. She has served on a number of boards since 1987, when she became a director of Selkirk Communications Limited, a diversified communications company. A year later she was appointed Chair of the Board and President and CEO. Several other directorships followed. In addition to TransAlta, Mrs. Kaufman currently serves on the boards of BCE Inc. and Bell Canada. She is also a director of HISTOR!CA, a private sector education initiative, and a member of the Canadian Advisory Board of Catalyst, a non-profit organization working to advance women in business.

At TransAlta, Mrs. Kaufman is the Chair of the Board of the Company and an ex-officio member of all committees of the Board.

Mrs. Kaufman holds a Bachelor of Civil Law degree from McGill University, Montreal, and a Master of Laws degree from the Université de Montréal.

GORDON S. LACKENBAUER *Corporate Director* Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. from 1990 to 2004. Prior to this, he was responsible for the principal activities of the firm, which included fixed income sales and trading, equity and debt, new issue underwriting and syndication. Mr. Lackenbauer has worked with many of Canada's leading utilities and has frequently acted as an expert financial witness testifying on the cost of capital, capital structure, and the fair rate of return before the Alberta Utilities Commission (then the APUB), the National Energy Board, and the Ontario Energy Board. His clients included Alberta Power (now ATCO Electric), Consumers' Gas IPL (now Enbridge), and TransCanada PipeLines, among others.

Mr. Lackenbauer is a director of NAL Oil & Gas Trust, CTVglobemedia Inc., and is a Governor of Mount Royal College. He was a director of Tembec Inc., until August 2007. At TransAlta, he is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board.

Mr. Lackenbauer holds a bachelor of arts in economics from Loyola College (Montreal, QC), as well as a master of business administration from the University of Western Ontario (London, ON). He is also a Chartered Financial Analyst.

MARTHA C. PIPER *Corporate Director* Dr. Piper was President and Vice-Chancellor of the University of British Columbia from 1997 to 2006. Prior to her appointment at the University of British Columbia, she served as Vice-President, Research at the University of Alberta. She served on the Boards of the Alberta Research Council, the Conference Board of Canada, and the Centre for Frontier Engineering Research. Dr. Piper was also appointed by the Prime Minister of Canada to the Advisory Council on Science and Technology, and she served as a member of the Canada Foundation for Innovation.

Dr. Piper is a director of the Bank of Montreal and of Shoppers Drug Mart Corporation, and is a member of the Canadian delegation to the Trilateral Commission, an organization fostering closer cooperation among the core democratic industrialized areas of the world. At TransAlta, Dr. Piper is a member of the Human Resources Committee of the Board.

Dr. Piper holds a bachelor of science in physical therapy from the University of Michigan (Ann Arbor, MI), a master of arts in child development from the University of Connecticut (Storrs, CT), and a doctorate of philosophy in epidemiology and biostatistics from McGill University (Montreal, QC). She has received honourary degrees from 15 international universities. She is an Officer of the Order of Canada and a recipient of the Order of British Columbia.

LUIS VÁZQUEZ SENTIES *Corporate Director and Independent Businessman* Mr. Vázquez is founder, President, CEO, and Chairman of Grupo Diavaz, an international constructor of offshore oil and gas platforms, developer of oil and gas fields, and a distributor of natural gas in Mexico. Grupo Diavaz began as a Mexican underwater diving operation that grew to become the world's second largest firm of its kind, servicing the offshore oil and gas industry in both exploration and production efforts.

Mr. Vázquez is Chairman of the Mexican Gas Association and vice-president of the Mexico chapter of the World Energy Council. He is past director of the American Gas Association. At TransAlta, Mr. Vázquez is a member of the Human Resources Committee of the Board.

STEPHEN G. SNYDER *Director, President and Chief Executive Officer of TransAlta Corporation since 1996.* Mr. Snyder guided TransAlta through its evolution from an Alberta-focused, regulated utility to an international power generator. Prior to joining TransAlta, Mr. Snyder held several CEO posts, namely with Camco Inc. (a subsidiary GE Canada Inc.), and Noma Industries Limited. While at GE, Mr. Snyder led the transformation of GE's Canadian-based businesses into global competitors. At Noma, he built a deeply rooted Canadian consumer products manufacturer into a North American industrial products company.

Mr. Snyder is a director of the Canadian Imperial Bank of Commerce and Chair of the Calgary Stampede Foundation. He is Chair of the Alberta Secretariat to End Homelessness. He is the past-chair of the Calgary Committee to End Homelessness, the Canada-Alberta ecoEnergy Carbon Capture & Storage Task Force, and of the Conference Board of Canada.

Mr. Snyder holds a bachelor of science in chemical engineering from Queen's University (Kingston, ON) as well as a master of business administration from the University of Western Ontario (London, ON).

TransAlta's directors are experienced senior business leaders bringing a broad mix of skills in the electricity sector, finance, law, government, regulatory and corporate governance. On behalf of TransAlta's shareholders, the Board of Directors is responsible for the stewardship of the Corporation, establishing overall policies and standards and reviewing strategic plans. In 2007, the directors met on 17 occasions, including one special meeting devoted exclusively to TransAlta's corporate strategy and direction.

After a detailed examination of the relationships between each of the directors and TransAlta, the Board determined that 10 of the existing 11 board members are independent, excluding only Stephen Snyder, President and CEO of the Company. All of the members of each of the committees of the Board are independent. In 2007, the Board had three committees, which are briefly described below. Further detailed information with respect to TransAlta's approach to corporate governance is contained in the 2007 Management Proxy Circular.

CORPORATE GOVERNANCE

AUDIT AND RISK COMMITTEE

The Committee provides oversight relating to the integrity of the Corporation's financial statements, the financial reporting process, the systems of internal accounting and financial controls, the risk identification assessment conducted by management and the programs established by management and the Board in response to such assessment, the internal audit function and the external auditors' qualifications, independence, performance, and reports. This committee met nine times in 2007. Committee chair: William D. Anderson. Members: Timothy W. Faithfull, Michael M. Kanovsky, Gordon S. Lackenbauer, and Donna Soble Kaufman (as an ex-officio member).

GOVERNANCE AND ENVIRONMENT COMMITTEE

The mandate of the Committee is to identify and recommend individuals to the Board for nomination as members of the Board and to develop and recommend to the Board a set of corporate governance principles applicable to the Corporation and to monitor compliance therewith. The Committee also provides oversight responsibilities with respect to environmental, health and safety practices, procedures and policies as established by management in relation to required legal/regulatory and industry standards or best practices. This committee met six times in 2007. Committee chair: Ambassador Gordon D. Giffin. Members: C. Kent Jespersen, Michael M. Kanovsky, Gordon S. Lackenbauer, Dr. Martha C. Piper, and Donna Soble Kaufman (as an ex-officio member).

HUMAN RESOURCES COMMITTEE

The Committee is responsible for reviewing and approving key compensation and human resource policies for the Corporation. Specifically, the committee is responsible for reviewing the Company's key human resources strategies, its equity-based and other compensation programs, and for recommending to the Board the compensation of the Corporation's executives. The committee also reviews and approves the succession management and development plan for key employees. This committee met six times in 2007. Committee chair: Stanley J. Bright. Members: Timothy W. Faithfull, C. Kent Jespersen, Dr. Martha C. Piper, Luis Vázquez Senties, and Donna Soble Kaufman (as an ex-officio member).

Plant Summary

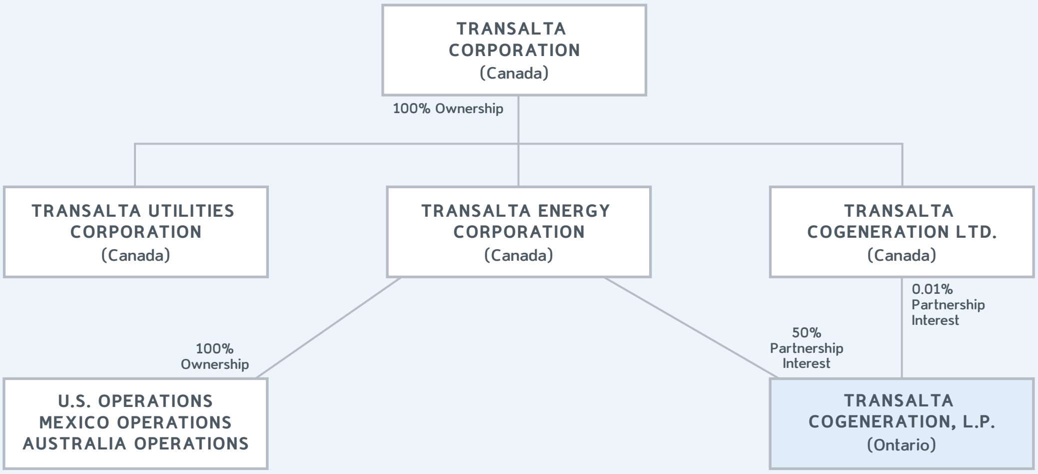
Region	Facility	Capacity (MW)	Ownership (%)	Net capacity ownership interest	Fuel	Revenue source	Contract expiry date
CANADA	Keephills	766	100	766	Coal	Alberta PPA	2020
ALBERTA	Sheerness	780	25	195	Coal	Alberta PPA	2020
25 facilities	Sundance	2,073	100	2,073	Coal	Alberta PPA	2017, 2020
	Wabamun [1]	279	100	279	Coal	Merchant	–
	Genesee 3	450	50	225	Coal	Merchant	–
	Keephills 3 [2]	450	50	225	Coal	Merchant	–
	Fort Saskatchewan	118	30	35	Gas	Long-term contract ("LTC")	2019
	Meridian	220	25	55	Gas	LTC	2024
	Poplar Creek	356	100	356	Gas	LTC/Merchant	2024
	Hydro assets [3]	801	100	801	Hydro	Alberta PPA	2013–2020
	Summerview [4]	70	100	70	Wind	Merchant	–
	Castle River [5]	46	100	46	Wind	LTC/Merchant	2011
	McBride Lake	76	50	38	Wind	LTC	2024
	Blue Trail [2]	66	100	66	Wind	Merchant	–
	TOTAL ALBERTA	**6,551**		**5,230**			
EASTERN CANADA	Mississauga	108	50	54	Gas	LTC	2017
5 facilities	Ottawa	68	50	34	Gas	LTC	2012
	Sarnia	575	100	575	Gas	LTC/Merchant	2022
	Windsor	68	50	34	Gas	LTC/Merchant	2016
	Kent Hills [2]	96	100	96	Wind	PPA	2033
	TOTAL EASTERN CANADA	**915**		**793**			
UNITED STATES	Centralia, WA	1,404	100	1,404	Coal	Merchant	–
18 facilities	Centralia Gas	248	100	248	Gas	Merchant	–
	Power Resources, TX	212	50	106	Gas	Merchant	–
	Saranac, NY	240	37.5	90	Gas	LTC	2009
	Yuma, AZ	50	50	25	Gas	LTC	2024
	Imperial Valley geothermal facilities [6]	327	50	164	Geothermal	LTC /Merchant	2016–2035
	Skookumchuk, WA	1	100	1	Hydro	–	–
	Wailuku	10	50	5	Hydro	LTC	2023
	TOTAL U.S.	**2,492**		**2,043**			
MEXICO *	Campeche	252	100	252	Gas/Diesel	LTC	2028
2 facilities	Chihuahua	259	100	259	Gas	LTC	2028
	TOTAL MEXICO	**511**		**511**			
AUSTRALIA	Parkeston	110	50	55	Gas	LTC	2016
5 facilities	Southern Cross [7]	245	100	245	Gas/Diesel	LTC	2016
	TOTAL AUSTRALIA	**355**		**300**			
TOTAL		**10,824**		**8,877**			

1 To be retired in 2010.
2 These facilities are currently under development.
3 Comprised of 13 facilities.
4 Comprised of 2 facilities.
5 Includes 7 individual turbines at other locations.
6 Comprised of 10 facilities.
7 Comprised of 4 facilities.

* *On February 20, 2008 TransAlta announced the sale of its Mexican business (511 MW gas-fired plants). The sale is subject to regulatory approvals.*

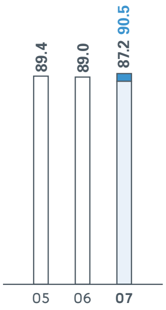
As of February 26, 2008.

Management's Discussion and Analysis

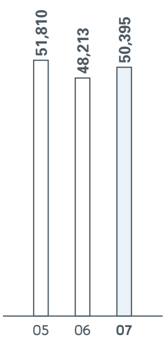


This management's discussion and analysis ("MD&A") should be read in conjunction with the consolidated financial statements included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All dollar amounts in the following discussion including the tables are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Feb. 26, 2008. 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.

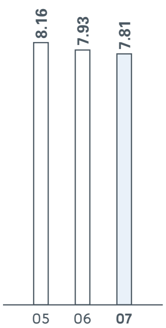
PLANT AVAILABILITY
(%)
■ adjusted for Centralia derates



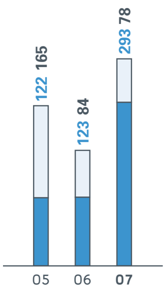
PRODUCTION
(GWh)



OM&A
($/installed MWh)



SUSTAINING CAPITAL EXPENDITURES
($ million)
■ routine and mine capital
□ planned maintenance



Performance Metrics

We are a wholesale power generator and marketer focused on the western regions of Canada and the United States. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets and have expertise in generation fuels including coal, natural gas, hydro, and renewable energy.

We have key measures that, in our opinion, are critical to 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 throughout the year at all times 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 88.5 per cent, which is in line with our long-term target between 90 and 92 per cent availability. Our availability in 2007 was 90.5 per cent after adjusting for derates at Centralia Thermal.

Production

Production is a significant driver of revenue in certain 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 contracts and in our merchant facilities.

For the year ended Dec. 31, 2007, production increased 2,182 GWh due to higher production at Centralia Thermal and lower planned outages and increased market demand at Sarnia partially offset by higher unplanned outages at Alberta Thermal.

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 reflect the cost of day-to-day operations. Our target is to absorb 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 megawatt-hour ("MWh") of capacity which has declined over the past three years.

OM&A costs have decreased over the last three years primarily due to reduced operational spending across the Generation fleet and general cost reductions, partially offset by the impact of the economic dispatch at Centralia Thermal in the second quarter of 2006, increased investment in our technological infrastructure, and higher stock compensation costs.

Safety

Safety is a top priority with all our staff, contractors and visitors. Our goal is to improve safety by 10 per cent each year and our ultimate target is for no incidents to occur.

	2005	2006	2007	Target 2008–2010
Injury Frequency Rate ("IFR")	1.41	1.96	**1.76**	Reduce >10% annually

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that needs consistent and stable capital expenditures.

In 2007, we spent $293 million on routine and mine capital and $78 million on planned maintenance. In 2006, we spent $123 million on routine and mine capital and $84 million on planned maintenance.

Our annual target for sustaining capital expenditures for the years 2009 and 2010 is approximately $230 to $260 million. In 2008, this spend is approximately $420 to $460 million due to equipment modifications at Centralia Thermal, investments in our mining operations, and productivity initiatives. These investments will result in improvements in reliability, heat rate, efficiency, and lower materials and labour costs. The projects are expected to pay back over the next two years. We expect to return to normal routine capital expenditure levels in 2010. We seek to reach these targets through focused planning, sound investment decisions, and solid execution against those plans.

Earnings and Cash Flow

We focus our base business on delivering strong earnings and cash flow growth. Comparable earnings per share[1] are targeted to increase in the low double-digit range per year with operating cash flows targeted between approximately $850 and $950 million.

	2005	2006	2007	2008–2010
Earnings per share (comparable basis)	0.82	1.16	**1.31**	Low double-digit growth
Cash from operating activities ($ millions)	620	490	**847**	850-950

In 2007, earnings per share on a comparable basis increased 13 per cent to $1.31 due to favourable pricing, higher production, and lower coal costs at Centralia Thermal, partially offset by higher unplanned outages at Alberta Thermal.

In 2006, earnings per share on a comparable basis increased to $1.16 due to incremental production from the addition of Genesee 3 and higher pricing in Alberta and at Centralia Thermal, partially offset by lower production at Centralia Thermal, higher coal costs, and lower hydro production.

In 2007, cash flow from operating activities increased $357 million mainly due to higher cash earnings, and receiving 12 months of contractually scheduled payments in 2007, compared to 11 in 2006.

In 2006, cash flow from operating activities decreased $130 million due to the timing of collection of receivables amounting to $185 million, partially offset by higher cash earnings. These accounts receivable balances in respect of November 2006 revenues were contractually scheduled to be paid, and were received, on Jan. 2, 2007. In 2005, the November contractually scheduled payments were received on Dec. 30, 2005.

Investment 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 stable investment grade credit ratings. Our objective is to maintain a cash flow to interest ratio of at least 4 times, a cash flow to debt ratio of at least 25 per cent, and a debt to invested capital ratio of at most 55 per cent.

At Dec. 31, 2007, our total debt (including non-recourse debt) to invested capital was 46.8 per cent (44.2 per cent excluding non-recourse debt) compared to the Dec. 31, 2006 ratio of 44.5 per cent and Dec. 31, 2005 ratio of 43.9 per cent. Cash flow to interest increased to 6.6 times compared to 5.5 times in 2006 and 4.7 times in 2005. Cash flow to total debt increased to 30.7 per cent from 26.2 per cent in 2006 and 23.0 per cent in 2005.

	2005	2006	2007	Target 2008–2010
Cash flow to interest (times)	4.7	5.5	**6.6**	Minimum 4
Cash flow to total debt (%)	23.0	26.2	**30.7**	Minimum 25
Debt to invested capital (%)	43.9	44.5	**46.8**	Maximum 55

We seek to maintain financial flexibility by using multiple sources of capital to finance capital allocation plans effectively, while maintaining sufficient liquidity in our investments to support contracting and trading activities. Further, it allows our commercial teams 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 goal is to achieve consistent return on common shareholders equity ("ROCE")[2] of greater than 10 per cent and total shareholder return ("TSR")[2] of 10 per cent or more per year.

The table below shows our historical performance on these measures:

	2005	2006	2007	Target 2008–2010
ROCE (%)	7.4	2.5	**9.8**	>10
Comparable ROCE (%)	7.4	9.0	**9.7**	>10
TSR (%)	47.6	9.2	**29.0**	>10

Business Environment

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we operate in are Western Canada, the Pacific Northwest, and Eastern Canada. The key characteristics of these markets are described below.

Demand

Demand for electricity is a key fundamental driver of prices in all markets. Weather and economic growth are the key drivers of changes in demand. Demand in all three of our major markets is growing at an average rate of one to three per cent per year. Alberta has seen the highest rate of demand growth, driven by a strong economy and development of the oilsands. In the Pacific Northwest, demand has grown at a moderate but steady pace. Demand in Ontario has been relatively weak due to reduced manufacturing activity and conservation.

1 *Comparable earnings is not defined under Canadian GAAP. Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of comparable earnings, including a reconciliation to net earnings.*

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. ROCE is a measure of the efficiency and profitablility of capital investments and is calculated by taking earnings before income tax and dividing by total assets less current liabilities. Comparable ROCE measures economic value created from capital investments and is calculated by taking comparable earnings before tax and dividing by total assets less current liabilities. 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 and dividends and is calculated by taking the internal rate of return of all cash flows.*

Supply

In all markets the cost of building new generating capacity has increased due to a shortage of component parts and increased costs of raw materials.

In Alberta, the existing thermal fleet is aging, resulting in more outages. As a result of strong growth, new generation is needed but is limited by transmission connections both within the province and to other markets. In the Pacific Northwest, sufficient supply exists in the nearer term. In Ontario, the anticipated retirement of thermal generation is placing demand on new nuclear, gas-fired, and wind sites, although transmission capacity constraints may affect how much new generation can be added.

Transmission

In simple terms, "Transmission" refers to the bulk delivery system of power and energy between the generating unit and the distribution system that links to wholesale and/or retail customers. Transmission lines themselves serve as the means to transport electricity from the generating unit to the individual distribution systems. Transmission systems are designed with additional capacity to allow for plants to go offline while still maintaining service to those connected to the transmission system.

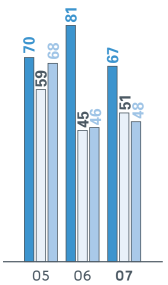
"Transmission Capacity" refers to the ability of the transmission line, or lines, to transport this bulk supply of electricity, in an amount that balances the demand needs to the generating supply, allows for an amount of power required for system integrity and security, and for reserve capacity to respond to contingency situations on the system. In the past, "adequate" transmission capacity, tightly correlated to demand growth, acted as a buffer to maintaining adequate supply during this period of new generation builds. Most transmission businesses in North America are still regulated.

However, in many markets, including Alberta, investment in transmission capacity has not kept pace with growth in demand for electricity. Delays in new transmission infrastructure projects were also caused by extensive consultation processes with landowners and changing regulatory requirements. As a result, additions of generating capacity, specifically wind projects, may not have access to markets depending upon their location until transmission upgrades and additions are completed.

Environmental Legislation and Technologies

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

AVERAGE SPOT ELECTRICITY PRICES
- Alberta (Cdn$/MWh)
- Mid-Columbia (US$/MWh)
- Ontario (Cdn$/MWh)



While carbon dioxide capture and sequestration technologies are being developed, storage technologies are not sufficiently advanced. Consequently, we are expecting environmental compliance costs to increase the cost of generating electricity.

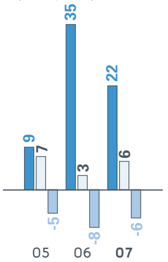
Electricity Prices

Spot electricity prices are important to our business as our merchant 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 Centralia Thermal, Genesee 3, Wabamun, and our contract at Sarnia minimize the impact of spot price changes.

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

The average spot electricity prices in each of the past three years in our three main markets are shown in the adjacent graph.

AVERAGE SPARK SPREADS
- Alberta vs. AECO (Cdn$/MWh)
- Mid-Columbia vs. SUMAS (US$/MWh)
- Ontario vs. Dawn (Cdn$/MWh)



For the year ended Dec. 31, 2007, spot prices in Alberta decreased due to unseasonably warmer weather, while prices in the Pacific Northwest and Ontario were higher compared to the same period in 2006.

Fuel Costs

Our generating facilities use either renewable fuel sources such as water, wind, and geothermal or use combustible fuels such as coal and natural gas. The costs that are incurred to supply fuel to our generating facilities affect our financial results.

Mining coal in Alberta is subject to cost increases due to increased overburden removal, inflation, and diesel commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing.

We have contracted out the supply of coal and transportation at Centralia Thermal to control these costs as our existing mines could not supply coal at an economical cost.

We purchase natural gas from outside companies coincident with production or it is supplied by our customers thereby minimizing our risk to changes in prices.

We closely monitor the risks associated with changes in electricity and natural gas 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.

Spark Spreads

Spark spread is the difference between the market price of electricity and its cost of production, including the cost of fuel and the heat rate of the plant generating electricity. This measure is important to us as it determines our potential profit. The price of fuel is also very important as this is the main variable cost in generating electricity.

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 prices of electricity, natural gas, and resulting spark spreads in our three major markets affect our Generation and Energy Trading businesses.

The effect of these prices upon the margins from our generating facilities and our trading activities are described in further detail below.

Results of Operations

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

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 obligations ("ARO"), valuation of goodwill, income taxes, and employee future benefits. See additional discussion under Critical Accounting Policies and Estimates in this MD&A.

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

Highlights and Summary of Results

During 2007, we:

- generated net earnings of $308.8 million compared to $44.9 million in 2006 and $186.3 million in 2005,
- generated earnings on a comparable basis[1] of $264.3 million compared to $233.8 million for 2006 and $161.3 million for 2005,
- generated cash flow from operations of $847.2 million compared to $489.6 million in 2006 and $619.8 million in 2005, and
- generated free cash flow[2] of $111.0 million compared to $229.9 million in 2006 and $159.7 million in 2005.

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

Year ended Dec. 31	2007	2006	2005
Availability (%)	87.2	89.0	89.4
Production (GWh)	50,395	48,213	51,810
Revenue	$ 2,774.7	$ 2,677.6	$ 2,664.4
Gross margin [3]	$ 1,544.0	$ 1,491.4	$ 1,442.0
Operating income before mine closure and asset impairment charges [3]	$ 541.1	$ 478.5	$ 456.8
Mine closure charges	–	(191.9)	–
Asset impairment charges	–	(130.0)	(36.2)
Operating income [3]	$ 541.1	$ 156.6	$ 420.6
Earnings from continuing operations	$ 308.8	$ 44.9	$ 174.3
Earnings from discontinued operations, net of tax	–	–	12.0
Net earnings	$ 308.8	$ 44.9	$ 186.3
Basic and diluted earnings per common share	$ 1.53	$ 0.22	$ 0.94
Cash flow from operating activities	$ 847.2	$ 489.6	$ 619.8
Cash dividends declared per share	$ 1.00	$ 1.00	$ 1.00

As at Dec. 31	2007	2006
Total assets	$ 7,178.7	$ 7,460.1
Total long-term financial liabilities	$ 2,880.7	$ 3,094.1

1 *Earnings on a comparable basis is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of earnings on a comparable basis, including a reconciliation to net earnings.*

2 *Free cash flow is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of these items, including a reconciliation to cash flow from operating activities.*

3 *Gross margin, Operating income before mine closure and asset impairment charges, and Operating income are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of these items, including a reconciliation to net earnings.*

Reported Earnings

In 2007, reported earnings increased to $308.8 million, compared to $44.9 million in 2006 and $186.3 million in 2005, as shown below:

Net earnings for the year ended Dec. 31, 2005	$ 186.3
Increased Generation gross margins before writedown of coal inventory and mark-to-market gains	49.5
Generation mark-to-market gains	35.5
Higher COD gross margins	8.8
Decrease in operations, maintenance, and administration costs	14.7
Increase in depreciation expense	(42.4)
Writedown of coal inventory to lower of cost and market (2006)	(44.4)
Centralia coal mine closure charges (2006)	(191.9)
Increase in asset impairment charges	(93.8)
Decrease in net interest expense	20.1
Increase in equity loss	(16.1)
Increase in non-controlling interests	(33.0)
Decrease in income tax expense	165.4
Earnings from discontinued operations, net of tax (2005)	(12.0)
Other	(1.8)
Net earnings for the year ended Dec. 31, 2006	$ 44.9
Increase in Generation gross margins before mark-to-market losses	83.2
Generation mark-to-market losses	(64.4)
Writedown of coal inventory to lower of cost and market (2006)	44.4
Decrease in COD margins	(10.6)
Decrease in operations, maintenance, and administration costs	4.5
Decrease in depreciation expense	4.4
Centralia coal mine closure charges (2006)	191.9
Asset impairment charges (2006)	130.0
Gain on sale of Centralia mining equipment	15.7
Decrease in net interest expense	35.2
Increase in equity loss	(32.5)
Decrease in non-controlling interest	3.5
Decrease in income tax expense	(146.2)
Other	4.8
Net earnings for the year ended Dec. 31, 2007	**$ 308.8**

Generation gross margins, before mark-to-market movements, increased by $83.2 million for the year ended Dec. 31, 2007 as a result of lower planned outages in Western Canada combined with favourable pricing, higher production, and lower fuel costs at Centralia Thermal, partially offset by higher coal costs and higher unplanned outages in Western Canada and the strengthening of the Canadian dollar relative to the U.S. dollar. In 2006, Generation gross margins increased before the writedown of coal inventory and mark-to-market gains by $49.5 million compared to 2005 due to incremental production from Genesee 3, favourable spark spreads and production at Poplar Creek, higher pricing and lower unplanned outages at Alberta Thermal, higher contract pricing at Centralia, increased gross margins at Sarnia, and higher trading margins. These increases were partially offset by higher unplanned outages and derates at Centralia Thermal, higher coal costs, and lower hydro production.

The majority of our electricity contracts in our Generation fleet are recorded under normal purchase/normal sale accounting or qualify for, and are recorded under, hedge accounting rules. To qualify for hedge accounting, the contract must be probable to be delivered to the customer from electricity generated from our facilities. As a result, for those contracts which we have elected hedge accounting, no gains or losses are recorded through the statement of earnings as a result of differences between the contract price and the current forecast of future prices. We do, however, record the changes in value of these contracts through the Statement of Other Comprehensive Income ("OCI"), but the amount of cash we receive under these contracts does not change. Upon settlement of these contracts, the difference between fair value and the contracted value is recorded in OCI and cash received.

Under hedge accounting rules we test for effectiveness at the end of each reporting period. This ensures that the amount of electricity we have contracted to supply is still likely to be provided and that the hedge provides a fixed cash flow. Where hedges are *effective,* we continue the accounting treatment described above. Where hedges are *ineffective,* that is where it is unlikely that we will have sufficient production capacity to fulfill those contracts and we will be required to fulfill that contract with electricity purchased in the market, or cash flow exposure exists, these hedges, in total or in part, are considered ineffective. The ineffective portion is no longer recorded as hedges and the changes in fair value are recorded in income and no longer through OCI.

As well, there are certain contracts in our Generation fleet 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 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. Please refer to the 'Financial Instruments' section of this MD&A for further details.

For the year ended Dec. 31, 2007, we recognized pre-tax mark-to-market losses of $28.9 million as a result of settlement of prior year mark-to-market contracts, new contracts entered into in the year and changes in forward prices. These amounts represented an increase in mark-to-market losses of $64.4 million for the year ending Dec. 31, 2007 compared to the same period in 2006. In 2006, we recognized mark-to-market gains of $35.5 million as a result of certain contracts at Centralia Thermal no longer qualifying for hedge accounting and from value changes in new contracts.

For the year ended Dec. 31, 2007, COD gross margins decreased $10.6 million compared to the same period in 2006 due to decreased gas and Eastern region trading margins in 2007 as a result of natural gas market volatility and the strengthening of the Canadian dollar relative to the U.S. dollar. In 2006, COD gross margins increased due to timing and maintenance of positions in the western region, partially offset by lower Eastern region results.

OM&A costs for the year ended Dec. 31, 2007 decreased $4.5 million compared to the same period in 2006 primarily due to reduced operational spending across the Generation fleet, partially offset by the impact of the economic dispatch at Centralia Thermal in the second quarter of 2006, increased investment in our technological infrastructure, and higher stock compensation costs. In 2006, OM&A decreased $14.7 million compared to 2005 due to lower planned maintenance and general cost reductions.

For the year ended Dec. 31, 2007, depreciation expense decreased $4.4 million compared to the same period in 2006 due to the impairment recorded in 2006 on turbines held in inventory and by lower depreciation as a result of the impairment of the Centralia Gas-fired facility ("Centralia Gas") recorded in 2006. In 2006, depreciation increased $42.4 million compared to 2005 due to recording an impairment on turbines held in inventory, revised depreciation rates at the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan, and Meridian plants, and revised ARO estimates.

In 2007, we sold equipment previously used in our Centralia mining operations and recorded a pre-tax gain of $15.7 million.

For the year ended Dec. 31, 2007, net interest expense decreased $35.2 million mainly due to lower long-term debt levels, higher interest income on cash deposits, and the strengthening of the Canadian dollar relative to the U.S. dollar. In 2006, net interest expense decreased $20.1 million due to lower long-term debt levels, recognition of settlement of hedges, and the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by higher interest rates.

For the year ended Dec. 31, 2007, equity loss increased $32.5 million compared to the same period in 2006 as a result of changes in Mexican tax laws, lower margins, and higher interest expense as a result of refinancing these subsidiaries, partially offset by the recognition of deferred financing fees in 2006. In 2006, equity loss increased $16.1 million due to lower margins and the recognition of deferred financing fees.

For the year ended Dec. 31, 2007, non-controlling interests decreased by $3.5 million due to lower earnings at TransAlta Cogeneration, L.P. ("TA Cogen") as a result of lower margins at Sheerness and Ottawa, partially offset by higher margins at Meridian. In 2006, non-controlling interests increased by $33.0 million due to the impairment of the Ottawa facility in 2005.

Income taxes increased compared to 2006 due to higher pre-tax earnings in 2007, lower benefits from tax rate reductions relating to prior periods, and tax recoveries on the 2006 asset impairment and mine closure charges, partially offset by the recovery from resolution of uncertain tax positions in 2007. In 2006, income taxes decreased due to the recording of applicable tax recoveries on the impairment charge at Centralia Gas as well as the costs recorded as a result of ceasing mining activities at the Centralia coal mine. Adjusting for these items, the effective tax rate for the year ended Dec. 31, 2007 was 24.2 per cent compared to 20.7 per cent in 2006, and 24.6 per cent in 2005.

Significant Events

Our consolidated financial results include the following significant events:

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 $47.4 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 ("CKI"), announced that it had paid for and acquired all of the limited partnership units of TransAlta Power, L.P. ("TransAlta Power") 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 PPA 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 $28.2 million charge in equity losses as a result of this change.

Normal Course Issuer Bid ("NCIB") Program

On Sept. 11, 2007, we announced an expansion of our NCIB program. We may 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 will continue until May 2, 2008. Purchases will be made on the open market through the Toronto Stock Exchange ("TSX") at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2007, we purchased 2,371,800 shares at an average price $31.59 per share. 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 $53.8 million.

Year ended Dec. 31	2007
Total shares purchased	**2,371,800**
Average purchase price per share	**$ 31.59**
Total cash paid	**$ 74.9**
Weighted average book value of shares cancelled	**21.1**
Reduction to retained earnings	**$ 53.8**

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 75 megawatts ("MW") of wind power. We will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills"). Commercial operations are expected to begin by the end of 2008.

On July 17, 2007, we amended our PPA with New Brunswick Power to increase capacity under the agreement from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills wind power project will also increase to $170 million from $130 million. We also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site.

Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

Sundance Unit 4 Uprate

During 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 the PPA customers. After flow-through, the net compliance costs are 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, TransAlta Utilities Corporation, a wholly owned subsidiary, 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 May 2010. The total payments made under this agreement in 2007 were $18.0 million.

Keephills 3 Power Plant

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

2006

Centralia Coal Mine

On Nov. 27, 2006, we ceased mining activities at our Centralia coal mine as a result of increased costs and unfavourable geological conditions. Inventory extracted up to the date on which we ceased operations was mostly consumed throughout 2007. Coal requirements for the foreseeable future are expected to be sourced from coal imported from the Powder River Basin ("PRB"). In 2007, we reduced production at the plant by approximately 2,500 gigawatt hours ("GWh"). The modifications to the equipment at Centralia Thermal are anticipated to be completed after the maintenance turnarounds.

We incurred an after-tax charge of $153.6 million ($0.76 per share) due to asset and inventory writedowns, reclamation liabilities, severance costs and other charges.

As required by GAAP, the restructuring charges appear on their appropriate lines on the Statements of Earnings. These have been summarized in the following table and are described below:

Writedown of coal inventory	$ 44.4
Impact on gross margin	(44.4)
Mine closure charges	
Mine equipment and infrastructure writedown	$ 72.1
ARO writedown	81.3
Severance costs and other	38.5
Total mine closure charges	191.9
Loss before income taxes	$ (236.3)
Income tax recovery	82.7
Net loss impact of event	$ (153.6)

Writedown of Coal Inventory

Since all coal requirements are now being sourced from an external source, the existing internally produced coal inventory was written down to fair market value, which was the current PRB cost at the time of cessation of mining activities.

Mine Equipment and Infrastructure Writedown

Mine equipment was valued at the lower of current net book value and fair value. The majority of this equipment was anticipated to be sold in 2007. Mining infrastructure, which includes processing facilities, was also written down to its expected fair values.

ARO Writedown

The unamortized cost of future reclamation expenses was recognized immediately.

Severance Costs and Other

This includes salaries payable to employees, estimated benefit obligations, other transition payments as a result of the closure, amounts accrued for estimated contract termination penalties, and writedown of materials and supplies. These costs were paid in 2007 for a total of $24.2 million with the difference between this amount and the amount above of $38.5 million due to the strengthening of the Canadian dollar relative to the U.S. dollar.

Further, since Centralia Thermal was not operating at full capacity in 2007 and 2008, certain contracts were no longer backed by physical production at the plant and therefore no longer qualified for hedge accounting. Therefore, under GAAP, we recorded these contracts at fair value and as a result of differences between market prices at that time and those of the contracts, recognized mark-to-market gains on these contracts. As well, we entered into additional contracts to offset some of this exposure and recorded these contracts at fair market value. As a result, on a net basis, based on current forward price estimates at that time, we recorded mark-to-market gains of $35.5 million. These mark-to-market adjustments, which are not included in the table above, had no cash impact on the 2006 financial statements but the fair market value will continue to change as market prices change until settlement occurs in future periods.

Centralia Gas Impairment

During our annual impairment review, we concluded that the full book value of our Centralia Gas facility was unlikely to be recovered from future cash flows due to changes in our outlook for the plant's profitability based on market dispatch rates and trading values. As a result, we recorded an $84.4 million after-tax ($0.42 per share) impairment charge to write the plant down to fair value.

Notice of Preferred Securities Redemption

On Nov. 22, 2006, we announced our intention to redeem all of our 7.75 per cent Preferred Securities, which had an aggregate principal of $175.0 million. We redeemed these securities on Jan. 2, 2007.

Designation of Eligible Dividends

Under the 2007 legislation enacted by the Department of Finance, Canadian residents are entitled to a higher gross-up and dividend tax credit in 2006 and subsequent years if they receive eligible dividends. The dividends paid by us during 2006 and 2007 are eligible dividends.

Amendment to Dividend Reinvestment and Share Purchase ("DRASP") Plan

On Oct. 20, 2006, we announced that effective Jan. 1, 2007, we were amending and thereby removing the five per cent discount on the price of shares purchased through the DRASP plan and suspending the issuance of shares from treasury. Instead, 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 TSX on the investment dates. Shares issuable under the DRASP plan have not been registered under any U.S. Federal or State Securities laws and U.S. persons or residents are not eligible to participate in the DRASP plan.

Wabamun Outage

In 2005, an oil spill at Lake Wabamun, Alberta forced us to shut down unit four of our Wabamun coal-fired plant for 39 days. In the fourth quarter of 2006, we settled a portion of our outstanding claim for lost margin and incremental expenses. The terms of the settlement are subject to a confidentiality agreement. The settlement is included in merchant revenues.

Sarnia Power Plant

On Feb. 15, 2006, we signed a five-year contract with the Ontario Power Authority ("OPA") for our Sarnia Regional Cogeneration Power Plant to supply an average of 400 MW of electricity to the Ontario electricity market. The contract was effective Jan. 1, 2006.

Centralia Thermal Reduced Production and Economic Dispatch

Due to heavy rainfall in the Pacific Northwest in the first quarter of 2006, we derated Centralia Thermal and started rebuilding our coal inventory. The impact of derating the plant during this time was partially offset by increasing coal imports and purchasing replacement power. We experienced 875 GWh of lower production during the first quarter of 2006 compared to the same period of 2005.

During the second quarter of 2006, lower market prices allowed us to purchase power at a price lower than our variable cost of production. As a result, Centralia Thermal did not operate for the majority of the second quarter. We experienced 1,936 GWh of lower production during the second quarter compared to the same period of 2005.

In the third quarter of 2006, the 702 MW unit 2 experienced a turbine blade failure. As a result of the event, total production was reduced by 727 GWh. Also, in the third quarter of 2006, higher unplanned outages resulted in 232 GWh of lower production.

In the fourth quarter of 2006, 358 GWh of production at Centralia Thermal was lost as a result of PRB coal test burns at the plant.

For the year ended Dec. 31, 2006, as a result of the above-mentioned events, total production at Centralia was 4,128 GWh lower than in 2005.

Purchase of Wailuku River Hydroelectric L.P.

On Feb. 17, 2006, we purchased a 50 per cent interest in Wailuku River Hydroelectric L.P. through Wailuku Holding Company, LLC ("Wailuku") for cash of U.S.$1.0 million (CDN$1.2 million). Wailuku had debt of U.S.$19.2 million (CDN$22.3 million) at the time of acquisition. Wailuku owns a run-of-river hydro facility with an operating capacity of 10 MW. MidAmerican Energy Holdings Company ("MidAmerican") owns the other 50 per cent interest in Wailuku.

Change in Depreciation Rate

In the first quarter of 2006, we changed the depreciation method of the Windsor-Essex, Mississauga, Ottawa, Meridian, and Fort Saskatchewan plants. Previously, these plants were amortized on a unit-of-production method over the life of the plants. After reviewing the estimated useful life and considering the uncertainty for the plants' operations beyond the terms of the current sales contracts, we determined that it was more reasonable to allocate the remaining net book value of the plants on a straight-line basis over the remaining term of the respective contracts. This increase in depreciation is offset by a reduction in earnings attributable to the non-controlling interests in our consolidated statement of earnings.

Keephills 3 Project

On March 14, 2006, we signed a development agreement with EPCOR Utilities Inc. ("EPCOR") to jointly examine the development of the Keephills 3 power project, a proposed 450 MW supercritical coal-fired plant adjacent to our existing Keephills facility.

2006 Federal and Alberta Budgets

On May 24, 2006, the Alberta budget received Royal Assent. As a result, the general corporate income tax rate for Alberta was reduced from 11.5 per cent to 10 per cent effective April 1, 2006. The federal budget received Royal Assent on June 22, 2006. As a result, the general corporate federal tax rate is to be reduced from 21 per cent to 19 per cent by Jan. 1, 2010. The corporate surtax was eliminated for taxation years ended after Dec. 31, 2007 and the federal capital tax has been eliminated effective Jan. 1, 2006. The carry-forward period for non-capital losses and investment tax credits earned after 2005 was extended from 10 to 20 years. As a result of these changes, we reduced income tax expense by $55.3 million.

2005

Commissioning of Genesee 3

On March 1, 2005, we, jointly with EPCOR, commissioned the Genesee 3 coal-fired facility. We own a 50 per cent interest in this unit.

Wabamun Outage

On Aug. 3, 2005, a CN Rail train derailment resulted in an oil spill in Lake Wabamun, Alberta. We were forced to shut down unit four of our Wabamun coal plant as a result. The facility was restored to full operations on Sept. 11, 2005.

Impairment of the Ottawa Facility

In the fourth quarter of 2005, after completing our impairment reviews, we concluded that the carrying value of the Ottawa cogeneration facility exceeded its fair value in the accounts of TA Cogen, a majority-owned subsidiary. Consequently, TA Cogen recorded an impairment provision of $78.3 million in the fourth quarter of 2005. However, in our accounts, the carrying value of the Ottawa facility is lower than that of TA Cogen. TA Cogen purchased this facility from us at a price that was higher than what we paid to construct it. We recognized a $36.2 million charge to reflect the difference in carrying values between our accounts and those of TA Cogen. This charge was offset by a reduction in the earnings attributable to the non-controlling interests in our consolidated statement of earnings. The net result is that the impairment of the plant in the accounts of TA Cogen had no impact on our net earnings.

Subsequent Events

Mexico Business

On Feb. 20, 2008, we announced the sale of our Mexican operations to InterGen Global Ventures B.V. ("InterGen") for U.S.$303.5 million. The transaction is subject to regulatory approvals in Mexico and is expected to close by the end of the second quarter of 2008. We will record a charge to the first quarter earnings of approximately $55 – $65 million to reflect the difference between the book value and sale price of these assets.

Blue Trail Wind Power Project

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

Dividend Increase

On Jan. 31, 2008, our Board of Directors approved an increase to the annual dividend from $1.00 to $1.08 per share. Our Board also declared a quarterly dividend of $0.27 per share on common shares, payable April 1, 2008 to shareholders of record at the close of business March 1, 2008.

Greenhouse Gas Emissions

On Jan. 24, 2008, the Government of Alberta announced its intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing carbon capture and storage technologies, developing conservation and energy efficiency programs, and through increased investment in clean energy technologies. The first stage of this program is to create focus groups or task forces for each of these three areas and develop action plans. We are assessing the impact of this proposal upon our operations and our own investment in environmental technologies and programs. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers.

Discussion of Segmented Results

GENERATION *Owns and operates hydro, wind, geothermal, gas- and coal-fired plants, and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. At Dec. 31, 2007, Generation had 8,431 MW of gross generating capacity[1] in operation (8,024 MW net ownership interest) and 387 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 26 of this annual report.*

During 2007, we completed an uprate on Unit 4 of our Sundance facility that added 53 MW of generating capacity. As well, during 2007 we increased the measured gross generating capacity of Sheerness by 5 MW (2.5 MW net of ownership interest) and Power Resources by 12 MW (6 MW net of ownership interest).

We have strategic alliances with EPCOR, ENMAX Corporation ("ENMAX"), and MidAmerican. The EPCOR alliance provided the opportunity for us to acquire a 50 per cent ownership in the 450 MW Genesee 3 project to build the Keephills 3 project. ENMAX and our Company 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.

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market. Margins are also typically 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.

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 results of the Generation segment are as follows:

Year ended Dec. 31	2007		2006		2005	
	Total	Per installed MWh [2]	Total	Per installed MWh [2]	Total	Per installed MWh [2]
Revenues	$ 2,719.6	$ 37.03	$ 2,611.9	$ 35.64	$ 2,607.5	$ 37.50
Fuel and purchased power	(1,230.7)	(16.76)	(1,186.2)	(16.19)	(1,222.4)	(17.58)
Gross margin	1,488.9	20.27	1,425.7	19.45	1,385.1	19.92
Operations, maintenance and administration	446.9	6.08	458.3	6.25	481.1	6.92
Depreciation and amortization	391.3	5.33	396.9	5.42	354.9	5.10
Taxes, other than income taxes	19.9	0.27	21.1	0.29	21.3	0.31
Intersegment cost allocation	27.3	0.37	27.8	0.38	26.0	0.37
Operating expenses	885.4	12.05	904.1	12.34	883.3	12.70
Operating income before mine closure and asset impairment charges [1]	603.5	8.22	521.6	7.11	501.8	7.22
Mine closure charges	–	–	191.9	2.62	–	–
Asset impairment charges	–	–	130.0	1.77	36.2	0.52
Operating income	$ 603.5	$ 8.22	$ 199.7	$ 2.72	$ 465.6	$ 6.70
Installed capacity (GWh)	73,447		73,287		69,528	
Production (GWh)	50,395		48,213		51,810	
Availability (%)	87.2		89.0		89.4	

Availability

Availability for the year ended Dec. 31, 2007 decreased to 87.2 per cent from 89.0 per cent compared to the same period in 2006 primarily as a result of derating at Centralia Thermal due to test burning PRB coal in 2007 and higher unplanned outages in Western Canada. The underlying availability after adjusting for Centralia Thermal derates is 90.5 per cent for the year ended Dec. 31, 2007.

In 2006, availability was slightly lower than 2005 due to higher unplanned outages and derates at Centralia Thermal, mostly offset by lower planned outages in Western Canada and lower planned and unplanned outages in Eastern Canada.

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, 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	$ 1,302.1	$ 449.4	$ 852.7	$ 28.69	$ 9.90	$ 18.79
Eastern Canada	3,775	7,173	442.9	302.6	140.3	61.75	42.19	19.56
International	13,222	20,889	974.6	478.7	495.9	46.66	22.92	23.74
	50,395	73,447	$ 2,719.6	$ 1,230.7	$ 1,488.9	$ 37.03	$ 16.76	$ 20.27

Year ended Dec. 31, 2006	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Western Canada	33,501	45,238	$ 1,291.4	$ 402.7	$ 888.7	$ 28.55	$ 8.90	$ 19.65
Eastern Canada	3,353	7,174	453.6	300.4	153.2	63.23	41.87	21.36
International	11,359	20,875	866.9	483.1	383.8	41.53	23.14	18.39
	48,213	73,287	$ 2,611.9	$ 1,186.2	$ 1,425.7	$ 35.64	$ 16.19	$ 19.45

Year ended Dec. 31, 2005	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	33,031	42,766	$ 1,234.6	$ 418.1	$ 816.5	$ 28.87	$ 9.78	$ 19.09
Eastern Canada	3,510	6,106	426.3	337.4	88.9	69.82	55.26	14.56
International	15,269	20,656	946.6	466.9	479.7	45.83	22.60	23.22
	51,810	69,528	$ 2,607.5	$ 1,222.4	$ 1,385.1	$ 37.50	$ 17.58	$ 19.92

1 *Operating income before mine closure and asset impairment charges is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of these items, including a reconciliation to cash flow from operating activities.*

2 *We have traditionally presented gross margins and other key elements of the income statement on a per MWh produced. While for specific types of contracts this is an effective measure of profitability between periods, levels of production and associated revenues and costs are not comparable across all plants within the Generation segment. To better gauge overall fleet performance and return on the investment in assets, we have presented overall results on an installed MWh basis, which is a measure of overall fleet capacity.*

Western Canada

Our Western Canada assets consist of five coal facilities, three gas-fired facilities, thirteen hydro facilities, and three wind farms with a total gross generating capacity of 5,222 MW (4,937 MW net of ownership interest). We are currently constructing a 450 MW (225 MW net of ownership interest) merchant thermal plant at our Keephills facility under a joint venture with EPCOR. The additional unit at our Keephills facility is scheduled to enter commercial production in 2011.

Our Sundance, Keephills, and Sheerness plants and hydro facilities operate under PPAs with a gross generating capacity of 4,030 MW (3,835 MW net of ownership interest). Under the PPAs, we earn monthly capacity revenues, which are designed to recover fixed costs and provide a return on capital for our plants and mines. We also earn energy payments for the recovery of predetermined variable costs of producing energy, an incentive/penalty for achieving above/below the targeted availability, and an excess energy payment for power production above committed capacity. Additional capacity added to these units that is not included in capacity covered by the PPAs is sold on the merchant market.

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

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

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

For the year ended Dec. 31, 2007, production decreased 103 GWh compared to 2006 due to higher unplanned outages at Alberta Thermal, partially offset by increased customer demand at Fort Saskatchewan, increased hydro production, and lower planned outages at Alberta Thermal.

In 2006, production increased 470 GWh compared to 2005 due to lower planned and unplanned outages at Alberta Thermal, increased production from Genesee 3, Poplar Creek, and Alberta Thermal, partially offset by lower PPA customer demand.

Gross margin for the year ended Dec. 31, 2007 decreased $36.0 million ($0.86 per installed MWh) compared to the same period in 2006 due to higher coal costs, higher unplanned outages at Alberta Thermal, and lower prices, partially offset by lower planned outages at Alberta Thermal and higher excess energy due to the uprate on Unit 4 of our Sundance facility.

In 2006, gross margin increased $72.2 million ($0.56 per installed MWh) compared to 2005 due to higher prices and increased production at various facilities, partially offset by lower hydro production and higher coal costs.

Eastern Canada

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

Production for the year ended Dec. 31, 2007 increased 422 GWh primarily resulting from favourable market conditions, higher customer demand and lower planned maintenance at Sarnia and increased production at Ottawa due to gas sales in the first quarter of 2006.

Production for the year ended Dec. 31, 2006 decreased 157 GWh primarily due to lower production at Ottawa and lower customer demand and higher planned maintenance at Sarnia.

For the year ended Dec. 31, 2007, gross margins decreased $12.9 million ($1.80 per installed MWh) mainly as a result of lower gas sales at Ottawa.

For the year ended Dec. 31, 2006, gross margins increased $64.3 million ($6.80 per installed MWh) primarily due to gas sales at Ottawa and incremental revenue at Sarnia.

International

Our international assets consist of gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,090 MW and 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 owned 50 per cent by us.

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

For the year ended Dec. 31, 2007, production increased 1,863 GWh due to lower unplanned outages combined with higher production at Centralia Thermal due to the facility being economically dispatched in the second quarter of 2006, partially offset by lower production at Centralia Gas.

For the year ended Dec. 31, 2006, production decreased 3,910 GWh due to higher unplanned outages, economic dispatch, and derates at Centralia Thermal.

For the year ended Dec. 31, 2007, gross margins increased $112.1 million ($5.35 per installed MWh) due to favourable market and contractual pricing and increased production at Centralia Thermal, the writedown of inventory related to the cessation of mining activities of the Centralia coal mine in 2006, and lower coal costs at Centralia Thermal, partially offset by mark-to-market losses in 2007 versus mark-to-market gains in 2006 and the strengthening of the Canadian dollar compared to the U.S. dollar.

For the year ended Dec. 31, 2006, gross margins decreased $95.9 million ($4.83 per installed MWh) due to reduced production at Centralia Thermal, higher coal costs, and the writedown of internally produced inventory to the lower of cost and market, partially offset by mark-to-market gains.

Operations, Maintenance, and Administration

For the year ended Dec. 31, 2007, OM&A expense decreased by $11.4 million primarily due to lower operational spending and planned maintenance expenditures, partially offset by savings realized from the economic dispatch at Centralia Thermal in the second quarter of 2006.

In 2006, OM&A expenses decreased $22.8 million from 2005 due to lower planned outages, general cost reductions, and from the economic dispatch at Centralia Thermal.

Planned Maintenance

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

Year ended Dec. 31	2007	2006	2005
Capitalized	$ 78.0	$ 84.2	$ 119.1
Expensed	54.0	55.4	68.3
	$ 132.0	$ 139.6	$ 187.4
GWh lost	2,056	2,325	2,818

Production lost in the year ended Dec. 31, 2007, decreased by 269 GWh from 2006 due to reduced planned outages across the fleet. In 2006, production lost decreased by 493 GWh for the same reason.

For the year ended Dec. 31, 2007, total capital and expensed maintenance costs decreased compared to the same period in 2006 primarily due to lower planned maintenance activity at our gas-fired facilities. During the year ended Dec. 31, 2006, capitalized and expensed maintenance costs were lower compared to the same period in 2005 due to the benefits from multi-year maintenance plans.

Depreciation Expense

For the year ended Dec. 31, 2007, depreciation expense decreased $5.6 million compared to 2006 due to the impairment recorded in 2006 on turbines held in inventory, lower depreciation at Centralia Gas, and the strengthening of the Canadian dollar versus the U.S. dollar, partially offset by the recording of ARO accretion at the Centralia coal mine, increased depreciation as a result of capital spending in 2006, and reduced life of certain parts at Centralia Thermal.

For active mines, accretion expense related to ARO is included in cost of sales. However, the Centralia coal mine is currently considered to be inactive and therefore, accretion expense is now recorded in depreciation expense. Accretion expense of $8.7 million and $8.2 million related to the Centralia coal mine was recorded in cost of sales, respectively, for the years ended Dec. 31, 2006 and Dec. 31, 2005.

Depreciation and amortization increased $42.0 million in 2006 compared to 2005 primarily due to the change in depreciation rates at the Windsor-Essex, Mississauga, Ottawa, Meridian, and Fort Saskatchewan plants, revised ARO estimates at Alberta Thermal, and the impairment recorded on turbines held in inventory. The change in depreciation rates at the above-mentioned plants resulted in an increase in depreciation expense that was offset by a decrease in non-controlling interests.

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 making 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 income in the period they occur.

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

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.

Previously, we recorded revenues and related costs for contracts settled in real-time physical markets on a gross basis. However, all of these contracts are held for trading, irrespective of the market in which they are settled. Therefore, we have concluded that it is more representative of the actual trading activities of COD to report the results of these contracts on a net basis.

Prior year balances have been reclassified to conform with the current year's presentation, as shown below. Current year balances have been prepared in the following table using previously disclosed methodologies for information purposes only.

Year ended Dec. 31	2007	2006	2005
Revenue	$ 272.9	$ 184.6	$ 231.0
Trading purchases	(217.8)	(118.9)	(174.1)
Net revenue	$ 55.1	$ 65.7	$ 56.9

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

Year ended Dec. 31	2007	2006	2005
Gross margin	$ 55.1	$ 65.7	$ 56.9
Operations, maintenance and administration	33.7	36.9	38.5
Depreciation and amortization	1.4	1.3	1.7
Intersegment cost allocation	(27.3)	(27.8)	(26.0)
Operating expenses	7.8	10.4	14.2
Operating income	$ 47.3	$ 55.3	$ 42.7

For the year ended Dec. 31, 2007, gross margins decreased $10.6 million compared to the same period in 2006 due to decreased gas and Eastern region trading margins as a result of natural gas market volatility and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2006, gross margins increased $8.8 million due to timing and management of positions in the western region, partially offset by lower margins in the Eastern region.

OM&A costs for 2007 decreased $3.2 million due to lower incentive costs as a result of decreased margins as well as lower project consulting expenses.

For the year ended Dec. 31, 2006, OM&A costs decreased $1.6 million compared to the same period in 2005 due to lower consulting costs, partially offset by increased trading staff levels.

The intersegment cost allocations are consistent with prior comparable periods.

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.

We estimate VAR using the historical variance/covariance approach. Currently, there is no uniform energy industry methodology for estimating VAR. 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.

Net Interest Expense

Year ended Dec. 31	2007	2006	2005
Interest on long-term debt	$ 144.7	$ 155.5	$ 169.3
Interest on short-term debt	26.3	12.7	14.9
Interest on preferred securities	–	13.6	16.5
Interest income	(31.7)	(13.3)	(8.7)
Capitalized interest	(6.0)	–	(3.4)
Net interest expense	$ 133.3	$ 168.5	$ 188.6

For the year ended Dec. 31, 2007, net interest expense decreased $35.2 million compared to the same period in 2006 due to lower long-term debt balances, the strengthening of the Canadian dollar relative to the U.S. dollar, the redemption of preferred securities, higher interest on cash deposits, and interest capitalized related to assets under construction, partially offset by higher short-term debt balances and gains recorded on financial instruments in 2006.

For the year ended Dec. 31, 2006, net interest expense decreased $20.1 million due to lower long-term debt balances, higher interest on cash balances, and the strengthening of the Canadian dollar to the U.S. dollar, partially offset by the recognition of gains on financial instruments in 2005.

Gain on Sale of Assets

As a result of the decision to cease mining activities at the Centralia coal mine, all associated mining and reclamation equipment was classified as being held for sale. All equipment was recorded at the lower of net book value or anticipated realized proceeds. These assets are included in the Generation segment.

During 2007, some of this equipment has been retained for reclamation activities and some was transferred to the Highvale mine for use in production of coal inventory. The equipment retained has been reclassified to property, plant, and equipment. The decision to retain equipment for use in reclamation activities at the Centralia coal mine and in operations at the Highvale mine was arrived at as the economics of retaining these assets was greater than the potential cash proceeds from disposing of these assets.

In 2006 we sold excess turbines in inventory for net proceeds of $20.3 million, which equaled their net book value.

Non-Controlling Interests

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in five gas-fired and one coal-fired generating facility with a total gross generating capacity of 814 MW. A private investor owns the minority interest in TA Cogen. Since we own a controlling interest in TA Cogen, under Canadian GAAP, we consolidate the entire earnings, assets, and liabilities in relation to TA Cogen's ownership of those assets. Non-controlling interests on the income statement and balance sheet relate to the earnings and net assets attributable to TA Cogen that are not owned by us. On the statement of cash flow, cash paid to the minority shareholder of TA Cogen is shown as 'Distributions to subsidiaries' non-controlling interests' in the financing section.

For the year ended Dec. 31, 2007, earnings attributable to non-controlling interests decreased $3.5 million due to lower margins at Sheerness and Ottawa, partially offset by higher margins at Meridian.

In 2006, non-controlling interests increased $33.0 million from the same period in 2005 due to the impairment recorded on TA Cogen's value in the Ottawa facility. Excluding the impairment charge, non-controlling interests decreased $3.2 million compared to the same period in 2005 due to higher earnings at TA Cogen in 2005.

Equity Loss

As required under Accounting Guideline 15, Consolidation of Variable Interest Entities, of the Canadian Institute of Chartered Accountants ("CICA"), our Mexican operations are accounted for as equity subsidiaries. However, these plants are owned by us and managed as part of the Generation segment.

The table below summarizes key information from these operations.

Year ended Dec. 31	2007	2006	2005
Availability (%)	**92.7**	90.8	93.4
Production (GWh)	**3,084**	2,918	2,751
Equity loss	**$ (49.5)**	$ (17.0)	$ (0.9)
Capital expenditures	**$ 1.0**	$ 10.0	$ 13.1
Operating cash flow	**$ (3.3)**	$ (7.2)	$ 9.2
Interest expense	**$ 27.4**	$ 31.6	$ 14.4

As at Dec. 31	2007	2006
Total assets	**$ 450.5**	$ 526.9
Total liabilities	**$ 368.7**	$ 404.1

For the year ended Dec. 31, 2007, availability increased primarily due to lower planned outages at Campeche and Chihuahua and unplanned outages at Chihuahua. Availability decreased for the year ended Dec. 31, 2006 compared to the same period in 2005 as a result of higher planned outages at the Chihuahua plant.

For the year ended Dec. 31, 2007, production increased 166 GWh due to higher customer demand at Chihuahua and lower planned outages at Campeche and Chihuahua.

In 2006, production increased 167 GWh compared to 2005 due to increased customer demand, partially offset by higher planned and unplanned outages.

As described in the 'Significant Events' section of this MD&A, on Oct. 1, 2007, the Mexican government enacted law introducing a flat tax system starting Jan. 1, 2008 and, as a result, we have recorded a $28.2 million charge to equity losses and a corresponding reduction in investments reflecting the expected impact of this change in law.

For the year ended Dec. 31, 2007, equity loss increased $32.5 million due to the income tax expense described above, lower margins, and increased interest costs as a result of refinancing these subsidiaries in 2006, partially offset by the recognition of deferred financing fees and the loss incurred on unwinding a cross-currency swap in 2006 related to the refinancing.

For the year ended Dec. 31, 2006, equity loss increased $16.1 million compared to 2005 due to recognition of the deferred financing fees resulting from the repayment of non-recourse debt and settlement of interest rate swaps.

We have initiated a strategic review of our Mexican operations and process to identify potential buyers for these assets. On Feb. 20, 2008, we announced the sale of our Mexican operations to InterGen for U.S.$303.5 million. Refer to the 'Subsequent Events' section in this MD&A for further details.

Income Taxes

Income tax expense under 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 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. We have seen several large reductions in future tax expense as a result of the Canadian government reducing future tax rates.

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

Year ended Dec. 31	2007	2006	2005
Earnings (loss) before income taxes [1]	$ 329.2	$ (80.9)	$ 213.9
Adjustments:			
Coal inventory writedown	–	44.4	–
Mine closure charges	–	191.9	–
Asset impairment charges	–	130.0	–
Turbine impairment	–	9.6	–
Change in tax law in Mexico	28.2	–	–
Earnings before income taxes and other adjustments [1]	$ 357.4	$ 295.0	$ 213.9
Income tax prior to adjustment for rate change [1]	86.5	61.2	52.6
Income tax recovery on one time adjustments	–	(131.7)	–
Income tax recovery from settlement of tax positions	(18.4)	–	(13.0)
Change in tax rate related to prior periods	(47.7)	(55.3)	–
Income tax expense (recovery) per financial statements	$ 20.4	$ (125.8)	$ 39.6
Net income	$ 308.8	$ 44.9	$ 174.3
Effective tax rate (%) [2]	24.2	20.7	24.6

During 2007, we settled certain taxation issues with the associated taxation authorities. As a result, we recorded a future income tax recovery of $18.4 million 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 $47.7 million for year ended Dec. 31, 2007. The comparable figure for the year ended Dec. 31, 2006 was $55.3 million.

Adjusting for the items mentioned above, tax expense increased for the year ended Dec. 31, 2007 from the same period in 2006 due to an increase in pre-tax income earnings and the effect of the change in mix of jurisdictions in which pre-tax income is earned.

1 *Earnings before income taxes and other adjustments, and income tax prior to adjustment for rate changes, are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 66 of this MD&A for a further discussion of this item, including a reconciliation to net earnings.*

2 *Effective tax rate is defined as income taxes prior to adjustment for rate change, divided by earnings before income taxes and other adjustments.*

Financial Position

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

	Increase/ (decrease)	Explanation of change
Cash and cash equivalents	$ (14.7)	Refer to Consolidated Statements of Cash Flows
Accounts receivable	(71.9)	Timing of receipt of contractually scheduled payments
Inventory	(22.9)	Lower inventory balances at Centralia Thermal
Restricted cash	(105.4)	Decrease in exchange rates of $48.6 and return of funds to TransAlta of $56.8
Investments	(29.9)	Net loss and debt repayments by equity subsidiaries
Long-term receivables	(26.6)	Revised estimate and reclassification of the current portion to accounts receivable
Risk management assets (current and long-term)	77.9	Adopting new accounting standards on financial instruments and from price changes
Property, plant and equipment, net	75.4	Capital additions, partially offset by the strengthening of the Canadian dollar compared to the U.S. dollar and depreciation expense
Goodwill	(12.6)	Strengthening of the Canadian dollar compared to the U.S. dollar
Assets held for sale, net	(80.7)	Assets retained for use in reclamation activities and for use in operations at the Highvale mine combined with sale of other assets
Intangible assets	(82.9)	Amortization expense and the strengthening of the Canadian dollar
Short-term debt	288.9	Net increase in short-term debt
Accounts payable and accrued liabilities	30.2	Timing of operational payments and the strengthening of the Canadian dollar
Recourse long-term debt (including current portion)	(268.8)	Scheduled debt payments and strengthening of the Canadian dollar compared to the U.S. dollar
Non-recourse long-term debt (including current portion)	(92.7)	Scheduled debt payments and strengthening of the Canadian dollar compared to the U.S. dollar
Risk management liabilities (current and long-term)	262.9	Result of adopting new accounting standards on financial instruments and from price changes
Deferred credits and other long-term liabilities (including current portion)	(81.8)	Normal accretion expense less liabilities settled, payment of Centralia coal mine closure costs, and revised ARO estimate
Net future income tax liabilities (including current portions)	(92.7)	Tax effect of adjustments related to new accounting standards on financial instruments and current year provisions
Non-controlling interests	(38.6)	Distributions in excess of earnings
Preferred securities (including current portion)	(175.0)	Preferred securities redeemed in the first quarter of 2007
Shareholders' equity	(129.4)	Adoption of new accounting standards, shares redeemed under the NCIB, and dividends declared, partially offset by net earnings and shares issued

Financial Instruments

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

The adoption of these new standards require us to "fair value" virtually all of our financial instruments, even in situations where hedge accounting is permitted. Prior to the adoption of these standards, only financial instruments where we were not permitted or did not elect to use hedge accounting were recorded at their fair values with changes in those values flowing directly through earnings.

The table below summarizes the current and prior accounting treatment of our financial instruments:

	Previous accounting treatment	Current accounting treatment
Energy trading contracts	Fair value with changes in value recorded in earnings	Fair value with changes in value recorded in earnings
Electricity supply contracts	Settlement accounting	Settlement accounting
Commodity-based contracts	Settlement accounting	Fair value with changes in value recorded in OCI; OCI reverses to earnings when contract settles
Net investment hedges	Fair value with changes recorded in cumulative translation adjustment	Fair value with changes recorded in OCI
Interest rate swaps	Settlement accounting	Fair value with changes recorded in earnings
Foreign exchange forwards	Fair value with changes recorded in asset	Fair value with changes recorded in asset

The most significant change related to the adoption of these new accounting standards is the requirement to fair value certain contractual positions related to our generating assets that have been designated as hedges. These positions were formerly accounted for on a settlement basis where revenues were recorded when the contracts were settled. The new standards require these contracts to be recorded at fair value at each balance sheet date with any change in fair value recorded in OCI. Fair values are based on current market curves and therefore fluctuate from period to period as prices change. When these contracts are ultimately settled, the fair value is removed from the balance sheet along with the related balance in OCI and revenue is recorded and cash is received.

Therefore, at the end of each period, the balance in AOCI and the corresponding risk management liability represents the value of our contract positions for our generating assets. However, though we have presented these balances accurately under GAAP, it does not fully represent the underlying economic reality and rationale. First, the amount that we will receive in the future when we deliver electricity under these contracts does not change; we will still receive the amount for which we have contracted. Second, this liability may imply that we could exit out of these contracts, which is often not possible in the short term due to market illiquidity. Third, these contracts have been entered into to seek stable cash flows, which is an important factor in maintaining investment grade credit ratios, which are a key element of our strategy. While we could leave these positions unhedged, we would be exposed to market volatility that would directly affect our actual cash flows. Finally, some of these contracts were entered into several years ago; given the movements in forward prices as these contracts are renewed they will be at higher prices and therefore reduce the amount recorded in AOCI.

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

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

	Price risk assets		Price risk liabilities		
	Current	Long-term	Current	Long-term	Net
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 – *as reported* [1]	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of COD net risk management assets (liabilities) outstanding at Jan. 1, 2007	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Jan. 1, 2007	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

1 *Previously reported balances have been reclassified* (Note 1 (T)).

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

Net risk management assets outstanding at Dec. 31, 2006 – *as reported*	$ 90.9
Fair value of COD net risk management liabilities outstanding at Jan. 1, 2007	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Jan. 1, 2007	47.7
Total fair value of risk management liabilities	(173.5)
Change in fair value	(264.4)
Tax	(87.1)
Adjustment to opening Accumulated Other Comprehensive Loss from fair values	$ (177.3)
Cumulative translation adjustment at Dec. 31, 2006	(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$ (241.8)

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

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 to our financial instruments presentation and related disclosure.

Risk Management Assets and Liabilities

We have two types of risk management assets and liabilities: (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 and the net investment in self-sustaining foreign subsidiaries.

Consolidated

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

As at Dec. 31	2007			2006		
Balance Sheet – Totals	**Energy Trading**	**Other**	**Total**	**Energy Trading**	**Other**	**Total**
Risk management assets						
Current	**$ 34.0**	**$ 59.2**	**$ 93.2**	$ 61.0	$ 11.2	$ 72.2
Long-term	**(4.1)**	**126.1**	**122.0**	21.9	43.2	65.1
Risk management liabilities						
Current	**(86.5)**	**(18.6)**	**(105.1)**	(30.3)	(2.1)	(32.4)
Long-term	**(192.5)**	**(11.7)**	**(204.2)**	(1.0)	(13.0)	(14.0)
Net risk management (liabilities) assets outstanding	**$ (249.1)**	**$ 155.0**	**$ (94.1)**	$ 51.6	$ 39.3	$ 90.9

The breakdown of the two components and their associated movements are described below.

1. Energy Trading

Our Energy Trading risk management assets and liabilities represent the fair value of unsettled (unrealized) COD transactions and certain Generation contracting activities that are accounted for on a fair value basis. Contracts qualifying for hedge accounting are identified as "Hedges." All other contracts are identified as "Non-hedges." With the exception of physical transmission contracts, the fair value of all Energy Trading activities is based on quoted market prices or model valuations.

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

As at Dec. 31	2007			2006
Balance Sheet – Energy Trading	**Hedges**	**Non-hedges**	**Total**	**Total related to Energy Trading**
Risk management assets				
Current	**$ 12.3**	**$ 21.7**	**$ 34.0**	$ 61.0
Long-term	**(4.5)**	**0.4**	**(4.1)**	21.9
Risk management liabilities				
Current	**(76.7)**	**(9.8)**	**(86.5)**	(30.3)
Long-term	**(191.9)**	**(0.6)**	**(192.5)**	(1.0)
Net risk management (liabilities) assets outstanding	**$ (260.8)**	**$ 11.7**	**$ (249.1)**	$ 51.6

As a result of adopting new accounting standards on financial instruments, as described on page 45, risk management assets and liabilities receiving hedge accounting are recorded at fair value. The impact upon previously reported values is shown in the table below along with the changes in those values during 2007:

As at Dec. 31	Hedges		Non-hedges		
Change in fair value of net assets (liabilities)	Fair value (market)	Fair value (model)	Fair value (market)	Fair value (model)	Total
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 – *as reported*	$ –	$ –	$ 52.7	$ (1.1)	$ 51.6
Net risk management liabilities outstanding at Jan. 1, 2007 – *fair value* [1]	(253.0)	(19.8)	52.7	(1.1)	(221.2)
Contracts realized, amortized or settled during the period	47.9	4.5	(31.9)	(3.9)	16.6
Changes in values attributable to market price and other market changes	(59.9)	0.9	19.9	(1.8)	(40.9)
New contracts entered into during the current period	(21.6)	–	(9.2)	8.6	(22.2)
Changes in foreign exchange values	22.9	–	(4.1)	(0.2)	18.6
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	–	(17.3)	–	–
Net risk management (liabilities) assets outstanding at Dec. 31, 2007 – *fair value*	**$ (246.4)**	**$ (14.4)**	**$ 10.1**	**$ 1.6**	**$ (249.1)**

For the year ended Dec. 31, 2007, the fair value of our net risk management liabilities associated with hedge positions decreased $12.0 million compared to Dec. 31, 2006 primarily due to value changes associated with contracts in existence at both Dec. 31, 2006 and Dec. 31, 2007, and the change in value of contracts settled in 2007. Changes in net risk management assets and liabilities for hedge positions are reflected within the gross margin of the Generation business segment to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until the delivery date of the underlying product and contract settlement occurs.

For the year ended Dec. 31, 2007, the fair value of our net risk management assets associated with non-hedge positions decreased $39.9 million compared to Dec. 31, 2006 primarily due to the value of contracts settled during the 2007, value changes associated with contracts in existence at both Dec. 31, 2006 and Dec. 31, 2007, and the value of contracts no longer receiving hedge accounting. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of both the COD and the Generation business segments.

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

	2008	2009	2010	2011	2012	2013 and thereafter	Total
Hedges							
Fair value based on market prices	$ (61.1)	$ (92.8)	$ (65.6)	$ (25.8)	$ (1.1)	$ –	$ (246.4)
Fair value based on models	(3.9)	(5.3)	(3.9)	(1.3)	–	–	(14.4)
	$ (65.0)	$ (98.1)	$ (69.5)	$ (27.1)	$ (1.1)	$ –	$ (260.8)
Non-hedges							
Fair value based on market prices	$ 9.8	$ 0.3	$ –	$ –	$ –	$ –	$ 10.1
Fair value based on models	2.0	(0.4)	–	–	–	–	1.6
	$ 11.8	$ (0.1)	$ –	$ –	$ –	$ –	$ 11.7
Grand total	$ (53.2)	$ (98.2)	$ (69.5)	$ (27.1)	$ (1.1)	$ –	$ (249.1)

Non-hedge transactions extending past 2008 are generally Generation asset-backed contracts that do not qualify for hedge accounting and have a low risk profile including long-term fixed for floating power swaps and heat rate swaps. Our Energy Trading activities are mainly transactions under 18 months in duration, thereby reducing credit risk and working capital requirements compared to longer term transactions.

1 *As a result of adopting new accounting standards* (Note 1(T)).

2. Other Risk Management Assets and Liabilities

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

As at Dec. 31		2007		2006
Balance Sheet – Other	Hedges	Non-hedges	Total	Total related to non-Energy Trading
Risk management assets				
Current	$ 56.9	$ 2.3	$ 59.2	$ 11.2
Long-term	126.1	–	126.1	43.2
Risk management liabilities				
Current	(16.0)	(2.6)	(18.6)	(2.1)
Long-term	1.2	(12.9)	(11.7)	(13.0)
Net risk management assets (liabilities) outstanding	$ 168.2	$ (13.2)	$ 155.0	$ 39.3

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

	Hedges	Non-hedges	Total
Net other risk management assets (liabilities) at Dec. 31, 2006 – *as reported*	$ 50.1	$ (10.8)	$ 39.3
Net other risk management assets (liabilities) at Jan. 1, 2007 – *fair value* [1]	58.0	(10.3)	47.7
Contracts realized, amortized or settled during the period	(39.5)	(1.3)	(40.8)
Changes in values attributable to market price and other market changes	112.0	(1.6)	110.4
New contracts entered into during the current period	37.7	–	37.7
Net other risk management assets (liabilities) outstanding at Dec. 31, 2007 – *fair value*	$ 168.2	$ (13.2)	$ 155.0

For the year ended Dec. 31, 2007, the fair value of our net risk management liabilities associated with non-hedge positions increased $2.9 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for non-hedge positions are reflected within interest expense.

For the year ended Dec. 31, 2007, the fair value of our net risk management assets associated with hedge positions increased $110.2 million compared to Dec. 31, 2006 primarily due to market value changes. Changes in net risk management assets and liabilities for hedge positions are reflected within interest expense to the extent transactions have settled during the period or ineffectiveness exists in the hedging relationship. To the extent these hedges remain effective and qualify for hedge accounting, the change in value of existing and new contracts will be deferred in OCI until settlement of the instrument, change in ownership, liquidation or reduction in the net investments of the foreign operation, or financial instrument being hedged.

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

	2008	2009	2010	2011	2012	2013 and thereafter	Total
Hedges	$ 41.0	$ 72.4	$ 24.0	$ 10.9	$ 4.1	$ 15.8	$ 168.2
Non-hedges	(0.4)	(12.8)	–	–	–	–	(13.2)
	$ 40.6	$ 59.6	$ 24.0	$ 10.9	$ 4.1	$ 15.8	$ 155.0

Employee Share Ownership

We employ a variety of stock-based compensation plans to align employee and corporate objectives. At Dec. 31, 2007, 1.2 million options to purchase our common shares were outstanding, with 0.8 million exercisable at the reporting date. At Dec. 31, 2006, 2.2 million options to purchase our common shares were outstanding, with 1.4 million exercisable at the reporting date. There is no impact on diluted EPS as per *Note 23* to the consolidated financial statements.

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 cash equivalent plus dividends thereon based upon our performance relative to companies comprising the Standard & Poor's ("S&P")/TSX composite total index. After three years, once PSOP eligibility has been determined, 50 per cent of the common shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. At Dec. 31, 2007, there were 1.0 million PSOP awards outstanding (2006 – 1.2 million). There is no impact on diluted EPS as per *Note 23* to the consolidated financial statements.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below executive 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, 2007, 0.7 million shares had been purchased by employees under this program (2006 – 0.6 million). This program is not available to officers and senior management.

1 *As a result of adopting new accounting standards* (Note 1(T)).

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, 2006.

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 $48.2 million to secure the obligations under the supplemental plan. Refer to *Note 33* to the consolidated financial statements.

Statements of Cash Flows

Year ended Dec. 31	2007	2006	Explanation of change
Cash and cash equivalents, beginning of year	$ 65.6	$ 79.3	
Provided by (used in):			
Operating activities	847.2	489.6	In 2007, cash inflows were due to cash earnings of $781.5 million and favourable change in working capital of $65.7 million, due to the timing of collections of revenues. In 2006, cash inflows were due to timings of collections from customers, and lower cash earnings.
Investing activities	(410.1)	(261.3)	In 2007, cash outflows were primarily due to additions of property, plant and equipment of $599.1 million and equity investment of $19.6 million, partially offset by realized gains on financial instruments of $107.0 million, proceeds on sale of property, plant and equipment at $46.9 million, and reduction in restricted cash of $56.8 million. In 2006, cash outflows were related to capital expenditures of $223.7 million and an increase in restricted cash of $333.1 million, partially offset by a decrease in equity investments of $226.4 million, realized gains on net investment hedges of $53.9 million, and proceeds on sale of assets of $29.4 million.
Financing activities	(443.8)	(243.2)	In 2007, cash outflows were due to dividends on common shares of $204.8 million, net repayment of long-term debt of $221.6 million, redemption of preferred securities of $175.0 million, distributions paid to non-controlling interests of $86.5 million, and repurchase of common shares under the NCIB of $74.9 million, partially offset by an increase in short-term debt of $288.9 million. In 2006, the cash used in financing activities increased due to repayment of long-term debt of $396.7 million, payment of distributions to non-controlling interests of $74.4 million, and dividend payments of $133.9 million, partially offset by an increase in short-term debt of $348.1 million.
Translation of foreign currency cash	(8.0)	1.2	
Cash and cash equivalents, end of year	$ 50.9	$ 65.6	

Year ended Dec. 31	2006	2005	Explanation
Cash and cash equivalents, beginning of year	$ 79.3	$ 101.2	
Provided by (used in):			
Operating activities	489.6	619.8	In 2006, cash inflows were due to timings of collections from customers, and lower cash earnings. In 2005, cash inflows were due to increased cash earnings offset by higher working capital requirements.
Investing activities	(261.3)	(242.5)	In 2006, cash outflows were related to capital expenditures of $223.7 million and an increase in restricted cash of $333.1 million, partially offset by a decrease in equity investments of $226.4 million, realized gains on net investment hedges of $53.9 million, and proceeds on sale of assets of $29.4 million. In 2005, capital expenditures of $325.9 million were offset by realized gains on net investment hedges of $89.8 million.
Financing activities	(243.2)	(396.3)	In 2006, the cash used in financing activities increased due to repayment of long-term debt of $396.7 million, payment of distributions to non-controlling interests of $74.4 million, and dividend payments of $133.9 million, partially offset by an increase in short-term debt of $348.1 million. In 2005, cash outflows were due to the redemption of preferred securities of $300.0 million, dividends on common shares of $99.2 million, distribution to subsidiaries' non-controlling interests of $77.5 million, repayment of long-term debt of $139.3 million, and repayment of short-term debt of $23.6 million, partially offset by the issuance of long-term debt of $200.0 million.
Translation of foreign currency cash	1.2	(2.9)	
Cash and cash equivalents, end of year	$ 65.6	$ 79.3	

Operating Activities

For the year ended Dec. 31, 2007, we paid $24.2 million of costs related to the closure of the Centralia coal mine.

Investing Activities

In 2007, we incurred $228.7 million in capital expenditures relating to the Kent Hills, Sundance Unit 4 uprate, and Keephills 3 projects. As well, we incurred $91.7 million in capital expenditures related to the rail handling and plant modifications at Centralia Thermal.

For the year ended Dec. 31, 2007, we realized $15.7 million from the sale of assets relating to our Centralia coal mine.

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

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

We have a total of $725.0 million of credit available from our committed and uncommitted credit facilities. At Dec. 31, 2007, credit utilized under these facilities is comprised of short-term debt of $651 million less cash on hand of $51 million and letters of credit of $550 million.

We have obligations to issue letters of credit to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At Dec. 31, 2007, we had issued letters of credit totalling $550 million compared to $633 million at Dec. 31, 2006. This decrease in letters of credit is due primarily to lower forward electricity prices in the Pacific Northwest. These letters secure certain amounts included in our balance sheets under 'Risk Management Liabilities' and 'Asset Retirement Obligations.'

We expect that our ability to generate adequate cash flow from operations in the short term and the long term to maintain financial capacity and flexibility to provide for planned growth remains substantially unchanged since Dec. 31, 2006. In the first quarter of 2008 we received $115.5 million worth of PPA revenue due to timing of contractually scheduled payments. Consequently, the effect of the timing of these payments is that we will receive 13 months of revenue in 2008.

On Feb. 25, 2008, we had approximately 201.2 million common shares outstanding.

On Feb. 24, 2008, we had 1.1 million outstanding employee stock options with a weighted average exercise price of $19.61. For the year ended Dec. 31, 2007, 0.8 million options with a weighted average exercise price of $20.84 were exercised resulting in 0.8 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $17.52.

Guarantee Contracts

We have provided guarantees of subsidiaries' obligations under contracts that facilitate physical and financial transactions using various derivatives. The guarantees provided for under all contracts facilitating physical and financial transactions in various derivatives at Dec. 31, 2007 was a maximum of $2.0 billion. In addition, we have a number of unlimited guarantees. The fair value of the trading and hedging positions under contracts where we have a net liability at Dec. 31, 2007, under the limited and unlimited guarantees, was $331.5 million as compared to $285.3 million at Dec. 31, 2006. The liabilities for these amounts are included in our balance sheets under 'Risk Management Liabilities' and 'Accounts Payable and Accrued Liabilities.'

We have also provided guarantees of subsidiaries' obligations to perform and make payments under various other contracts. The amount guaranteed under these contracts at Dec. 31, 2007 was a maximum of $1.3 billion, as compared to $788.3 million at Dec. 31, 2006. In addition, we have a number of unlimited guarantees.

We have approximately $0.7 billion of credit available from our committed and uncommitted credit facilities to secure these exposures.

Working Capital

For the year ended Dec. 31, 2007, the excess of current liabilities over current assets of $686 million is mainly due to higher short-term debt balances, and lower accounts receivable balances, partially offset by receiving November 2006 revenues, as contractually scheduled, on Jan. 2, 2007.

For the year ended Dec. 31, 2006, the negative change in working capital is primarily due to the timing of collection of revenues under PPAs, as described above and the reclassification of $175.0 million of preferred securities to current liabilities that were redeemed in January 2007, offset by an increase in accounts receivable.

Capital Structure

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance.

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

As at Dec. 31	2007		2006		2005	
			(Restated, Note 1)		*(Restated, Note 1)*	
Debt, net of cash, and interest-earning investments	**$ 2,459.2**	**47%**	$ 2,517.1	45%	$ 2,525.7	44%
Preferred securities, including current portion	**–**	**–**	175.0	3%	175.0	3%
Non-controlling interests	**496.4**	**9%**	535.0	9%	558.6	10%
Common shareholders' equity	**2,298.5**	**44%**	2,427.9	43%	2,497.0	43%
	$ 5,254.1	**100%**	$ 5,655.0	100%	$ 5,756.3	100%

Contractual repayments of long-term debt, commitments under operating leases, fixed price purchase contracts, and commitments under mining agreements are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Long-term debt	Interest on long-term debt [1]	Total
2008	$ 47.0	$ 10.8	$ 45.2	$ 153.8	$ 120.9	$ 377.7
2009	26.3	9.5	49.3	237.6	112.5	435.2
2010	6.8	9.1	45.0	27.8	99.3	188.0
2011	6.8	8.9	44.8	250.5	88.1	399.1
2012	6.8	8.9	44.5	319.5	69.1	448.8
2013 and thereafter	40.9	67.3	355.1	857.7	502.4	1,823.4
Total	$ 134.6	$ 114.5	$ 583.9	$ 1,846.9	$ 992.3	$ 3,672.2

1 *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 have no such off-balance sheet arrangements.

Related Party Transactions

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

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

Climate Change and Air Emissions

The variety 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 to ensure we are able to continuously deliver low cost electricity.

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.

On Jan. 24, 2008, the Government of Alberta announced its intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing carbon capture and storage technologies, developing conservation and energy efficiency programs, and through increased investment in clean energy technologies. The first stage of this program is to create focus groups or task forces for each of these three areas and develop action plans. We are assessing the impact of this proposal upon our operations and our own investment in environmental technologies and programs.

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 intensity are set on a facility by facility basis. The legislation requires a 12 per cent reduction in GHG emission intensity from a baseline of the average of 2003 to 2005 emission levels. 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 reduction requirements gradually increase until the eighth year by which time emissions must be 12 per cent below the established baseline. Emissions over the baseline must be mitigated either through contributions to an Alberta Technology Fund at $15 per tonne, or through the purchase and retirement of Alberta-based offsets from non-regulated sectors. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers. After flow-through, the annual net compliance costs were $1.4 million for 2007, and are estimated to be approximately $5 million per year until we are able to meet the targets for GHG emissions under the Act.

On April 26, 2007, the Canadian government released details of its proposed environmental legislation. The federal plan calls for an 18 per cent reduction in GHG emission intensity starting in 2010, increasing to a 20 per cent absolute reduction requirement by 2020. The proposed legislation also calls for a reduction in air pollutants such as sulphur dioxide, nitrous oxide, mercury, and particulates starting in the 2012 – 2015 period. Proposed reduction caps range from 45 per cent to 60 per cent of current levels. A number of material details in the federal plan are still to be determined, including its interaction with provincial programs, which will allow a reasonable determination of future compliance costs.

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

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect on July 22, 2007. Our operations will not be impacted by the bill's performance standards at the current time, provided the facilities do not change ownership or enter into power sales contracts longer than five years. Additionally, further emissions requirements are being considered for our Centralia plant for mercury and nitrous oxide; however, final determinations are not anticipated until late 2008. Federally, the U.S. government continues to contemplate a number of proposed GHG bills but to date no clear outcome or schedule is evident.

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

TransAlta Activities

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 believe 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 encompasses several elements:

- construction of renewable power sources,
- active participation in policy discussions,
- development of cleaner generation technologies, and
- continued investment in an offsets portfolio.

Our investment in renewable power sources continues through the building of renewable power resources such as the Kent Hills and Blue Trail wind farms.

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

As one of the founders, and active members, of the Clean Coal Power Coalition, we aim to secure a future for coal-fired electricity generation, within the context of Canada's multi-fuelled electricity industry, by proactively addressing environmental issues in cooperation with government and our stakeholders.

We are also part of a group of companies participating in the Integrated CO_2 Network to work with the Albertan and Canadian governments to develop carbon capture and storage systems for Canada.

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. As described earlier, we are in the process of finalizing mercury control technology. In prior years we have invested in other capture technologies such as those for sulfur dioxide. We are currently investigating opportunities for carbon capture, sequestration, and storage technologies.

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

In addition, we continue to pursue 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.

2008 Outlook

Business Environment

Demand and Supply

In 2008, we believe that the growth in demand for electricity will continue at the level seen over the past three years. Without significant new generating capacity additions over the next five years and increased environmental compliance costs, the continued upward pressure on prices will continue.

Power Prices

For the remainder of 2008, power prices in Alberta are expected to remain strong due to an expected cooler than average winter. Prices in the Pacific Northwest are anticipated to face upside pressure in 2008 due to cooler than normal temperatures. Ontario power prices are forecast to strengthen compared with 2007 because of a tighter supply and a cooler winter.

In 2008, approximately four per cent of production at our gas-fired facilities and 19 per cent of production at our coal-fired facilities is exposed to market fluctuations in energy commodity prices. We closely monitor the risks associated with these commodity price changes on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Operations

Production, Availability, and Capacity

Generating capacity is expected to increase due to the completion of Kent Hills late in 2008. Production and availability are expected to increase due to lower unplanned outages and lower derates as a result of test burning at Centralia in 2007, partially offset by higher planned maintenance.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to increased overburden removal, inflation, and diesel commodity prices. Seasonal variations in coal mining at our Alberta mines are minimized through the application of standard costing. 2008 Alberta mining costs are expected to be consistent with those seen in 2007. Fuel at Centralia Thermal is purchased from an external supplier. These contract prices are expected to increase slightly from those seen in 2007 due to contract and commodity escalations.

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

Operations, Maintenance, and Administration Costs

OM&A costs per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs per MWh of installed capacity are anticipated in 2008 to be higher compared to 2007 due to higher planned maintenance activities.

Planned Maintenance

	Coal	Gas and hydro	Total
Capitalized	$ 65–70	$ 45–50	$ 110–120
Expensed	65–70	5–10	70–80
	$ 130–140	$ 50–60	$ 180–200
GWh lost	2,200–2,300	425–475	2,625–2,775

In 2008, we expect to lose approximately 2,625 to 2,775 GWh of production due to planned maintenance. During 2008, we have no significant planned maintenance activities at our Mexican operations.

Change in Estimate of Certain Components at Centralia Thermal

As a result of our decision to stop mining at the Centralia coal mine, we are now procuring all of the coal used in production at Centralia Thermal from several selected third-party vendors. The coal that is delivered from these vendors is of a different chemical composition and has a different thermal content than the coal from our Centralia coal mine. Previously, this externally sourced coal was blended with internally produced coal to maximize the output from Centralia Thermal. However, with the cessation of mining, this locally mined coal is no longer available to be blended and therefore the coal being consumed burns at a higher temperature and produces a different composition of ash. The boiler at Centralia Thermal is not currently configured to run optimally at these higher temperatures or with the different ash compositions.

During 2007, test burns were conducted to determine what equipment modifications needed to be performed to optimize this consumption of third-party delivered coal. At the end of the third quarter of 2007, a technical plan was completed including which components needed to be replaced to ensure continued maximum output from Centralia Thermal. These equipment modifications are scheduled to occur during planned maintenance outages in 2008 and 2009. As a result, the estimated useful life of the component parts that are to be replaced during these planned outages have been reduced and this change in estimate of useful life will be recognized over the period up to the related maintenance outage.

As a result, depreciation expense is expected to increase over the same comparative periods in 2006 by:

	2008				2009	
	Q1	Q2	Q3	Q4	Q1	Q2
Increase in depreciation	$ 5.5	$ 5.5	$ 1.3	$ 1.3	$ 1.3	$ 1.3

Energy Trading

Earnings from our Energy Trading business are affected by prices in the market, the positions taken, and duration of those positions. We routinely monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our objective is for proprietary trading to contribute annually 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 mostly offset foreign currency revenues.

Net Interest Expense

Net interest expense for 2008 is expected to be higher due to increased borrowings as a result of growth. However, changes in interest rates and in the value of the Canadian dollar to the U.S. dollar could affect the amount of net interest expense incurred.

Liquidity and Capital Resources

With the anticipated increased volatility in power and gas markets, market trading opportunities are expected to increase, which can potentially cause the need for additional liquidity. To mitigate this liquidity risk, we maintain and monitor a $1.8 billion committed credit facility and monitor exposures to determine any expected liquidity requirements.

Projects and Growth

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

Four significant capital projects that we are currently working on are Keephills 3, Kent Hills, Centralia modifications, and Blue Trail projects. A summary of each of these projects is outlined below:

Project	Total spend (millions)	Expected 2008 spend (millions)	Expected completion date	Details	Status
Keephills 3	$ 815	$ 320–330	Q1 2011	A 450 MW (225 MW net of ownership) coal-fired supercritical plant in a partnership with EPCOR	On track
Kent Hills	$ 170	$ 135–145	Q4 2008	96 MW wind farm in New Brunswick to operate under a power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation	On track
Centralia modifications	$ 185	$ 60–65	Q3 2009	Convert the boilers and critical fuel systems at Centralia Thermal to ensure that both units at this facility can produce full output, on a sustainable basis, solely burning PRB coal	On track
Blue Trail	$ 115	$ 20–25	Q4 2009	A 66 MW wind farm in southern Alberta	On track

Sustaining Expenditures

Sustaining expenditures include planned maintenance, regular expenditures on plant equipment, systems and related infrastructure, as well as investments in our mines. For 2008, our estimate for total sustaining capital expenditures, excluding Mexico and Centralia modifications listed above, is between $365 million and $395 million, allocated among:

- $155–$165 million for routine capital,
- $100–$110 million for mining equipment, and
- $110–$120 million on planned maintenance.

Financing

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

Risk Management

Our business activities expose us to a wide variety of risks. Our goal in managing these risks is to protect our Company from an unacceptable level of earnings or financial exposure while still enabling business processes and opportunities. We use a multi-level risk management oversight structure to manage these objectives, by ensuring that the risks arising from our business activities, the markets in which we operate, and the political environments in which we operate is mitigated.

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

Board of Directors provides stewardship of the Corporation and establishes policies and procedures.

Audit and Risk ("A&R") Committee, 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 A&R Committee approves our Commodity Risk and Financial Exposure Management policies.

Exposure Management Committee ("EMC") is chaired by our Chief Financial Officer and is comprised of the Executive Vice-President of Commercial Operations and Development, Vice-President and Treasurer, Vice-President Financial Operations, Vice-President and Comptroller, and the Director of Risk Management. The EMC is responsible for reviewing, monitoring, and reporting on our compliance with approved financial and commodity risk exposure management policies.

Corporate Treasury is responsible for the management, oversight, and reporting of our capital position, credit risk, and funding risks. One of its goals is to minimize the cost of capital while optimizing returns to shareholders.

Risk Management is staffed by competent and experienced risk professionals who are responsible for enterprise risk reporting to the Board, analyzing commercial risk exposures in our assets and trading operations, as well as ensuring our daily market price exposure is kept within VAR limits. The Risk Management group uses a variety of processes and models to perform this analysis.

Our risk management practices address key risk factors. These are described in greater detail as follows.

Risk Controls

Our management of these risks is also described in the respective sections. Our risk controls have several key components:

Enterprise Tone Our corporate values are clearly articulated throughout the organization. Employees sign agreements outlining their commitment to our corporate code of conduct.

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. 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 EM Committee. This reporting includes analysis of risks being assumed, existing risk exposures, and recommendations for any suggested course of action. This frequent reporting provides for effective and timely risk management and oversight.

Whistleblower System 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, Legal and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the Audit and Risk Committee.

Risk Factors

Risk is inherent in all business activities and cannot be entirely eliminated. However, shareholder value can be maintained and enhanced by identifying, mitigating, 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 2007. 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 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 also play an important role in the management of water flows and levels in several key areas of Alberta, including two major cities. 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 Generation Technology groups in order to be proactive in plant maintenance,
- 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 have sufficient resources in order for us to be able to generate sufficient electricity to meet the requirements of 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 income are described below:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Availability/production	1%	$ 20.5

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. 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 suffer a reduction in electrical or capacity payments. For merchant facilities, an extended 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.

Technology used in our generating facilities is selected and maintained with the goal of maximizing the return on those assets. If technology advances significantly beyond the capabilities of our existing fleet, our profitability and carrying value of assets may be affected.

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 with our equipment 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,
- 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,
- 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, 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 electricity price commodity 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 VAR methodologies. VAR is the primary measure used to manage COD's exposure to market risk resulting from trading activities.

In 2007, we had approximately 96 per cent of production under short-term and long-term contracts and hedges (2006 – 95 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
- 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 2007, 81 per cent (2006 – 68 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2006 – 100 per cent) of our purchased coal costs were contractually fixed.

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

The sensitivities of price changes to our net income are described below:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Electricity price	$1.00/MWh	$ 8.3
Natural gas price	$ 0.1/GJ	$ 1.5
Coal price	$1.00/tonne	$ 15.0

Fuel Supply Risk

We buy natural gas and some of our coal to supply the fuel needed to operate our facilities. The ability to have sufficient fuel available when required for generation could have an impact upon our ability to produce electricity under contracts and for merchant sale opportunities.

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 to our customers. 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 supply of coal from third parties. As at Dec. 31, 2007, approximately 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,
- negotiating for the availability of sufficient trains to deliver the coal requirements at Centralia Thermal in excess of five years, and
- upgrading the coal handling and storage facilities at Centralia Thermal to ensure that the coal being delivered can be processed in a timely and efficient manner.

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 from exceeding emission caps, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these 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 ISO-based 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 greenhouse gases, 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 2007, we spent approximately $46 million (2006 – $50 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 build Canada's first clean coal power plant.

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 comprised of the ability of a counterparty to fulfill their financial obligations to us or where we have made a payment in advance of a product or service being delivered. The inability to collect cash due to us or receiving products or services would have an adverse impact upon our cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to established policies that define credit limits based on creditworthiness of counterparties, define contract term limits, and credit concentration with any specific counterparties,
- using formal signoff on contracts that include commercial, finance, 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, and
- reporting our exposure on a variety of methods which 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 the 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 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.

A summary of our credit exposure for commodity trading operations at Dec. 31, 2007 is provided below:

Counterparty credit rating	Net exposure
Investment grade	$ 47.2
Non-investment grade	$ 5.1
No external rating, internally rated as investment grade	$ 20.2
No external rating, internally rated as non-investment grade	$ 2.2

In addition to the above, we have credit exposure to counterparties under long-term sales contracts. There is no net exposure in our commodity trading operations for any counterparty greater than 10 per cent.

The maximum credit exposure to any one customer for commodity trading operations, excluding the California Independent System Operator ("ISO") and California Power Exchange ("PX"), and including the fair value of open trading positions, is $6.3 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. We have exposures primarily to the U.S., Mexican, and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our earnings or value of our foreign investments, to the extent 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, 2007, we hedged approximately 99 per cent (2006 – 88 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 foreign operations earnings.

Translation gains and losses related to the carrying value of our foreign operations are included in AOCI in shareholders' equity. At Dec. 31, 2007, the balance in this account was a $244.8 million loss (2006 – $64.5 million loss).

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

Factor	Increase or decrease (Foreign Currency)	Approximate impact on earnings and cash flow (after-tax)
Exchange rate	$0.10	$ 0.2

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used in proprietary trading activities, commodity contracting, and in debt and equity markets. 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 stable investment grade credit ratings.

We are exposed to liquidity risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require us to provide collateral when the fair value of these contracts is in excess of any credit limits granted by our counterparties and the contract obliges us to provide the collateral. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and accordingly increase the amount of collateral we may have to provide.

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and 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, and
- maintaining investment grade credit ratings.

The maximum amount of collateral that we would have to provide under existing contracts for our commodity trading operations and with our existing credit ratings is $33.4 million at Dec. 31, 2007. Total collateral available to the Corporation was approximately $725 million.

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, 2007, approximately 34.8 per cent (2006 – 28.4 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 earnings is shown below:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Interest rate	1%	$ 6.2

Project Management Risk

As we are currently building three generating projects, we face risks associated with cost-overruns, delays, and performance.

We attempt to minimize these risks by:

- 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 EPCOR 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, warranties and source agreements 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.

This risk can occur in several ways:

- potential disruption as a result of labour action at our generating facilities,
- reduced productivity due to turnover in out-of-scope 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.

Of our labour force, 46 per cent is covered by 13 collective bargaining agreements. In 2007, eight agreements were renegotiated. We anticipate negotiating two agreements in 2008. 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. The generation of electricity is under increased political scrutiny due to decreasing reserve margins, increased demand, and a lack of new generating capacity. 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 political risk insurance.

Transmission Risks

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 reliability and capacity on the existing transmission facilities, the risk associated with the existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continues to develop.

Transmission risks are mitigated through:

- force majeure clauses in the Alberta PPAs,
- developing and ensuring continued access to multiple transmission lines, and
- working with governments, regulators, and stakeholders to ensure that transmission constraints are removed through timely transmission development or technology additions.

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:

- 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, Legal, and Human Resources in determining the appropriate course of action. These concerns and any actions taken are discussed with the Audit and Risk Committee. All employees 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 GAAP, based on all information currently available.

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

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Tax rate	1%	$ 3.8

The effective income tax rate can change depending on the mix of earnings from various countries. Increased operating income will incur income tax expense at a rate of approximately 30 per cent compared to the forecasted overall range of 23 to 28 per cent.

Legal Contingencies

We are occasionally named as a defendant in various claims and legal actions. Exposure to these claims is mitigated through levels of insurance coverage considered appropriate by management and active management of these claims. Except as disclosed in *Note 28* to the consolidated financial statements, we do not expect the outcome of the claims or potential claims to have a materially adverse effect on the Corporation 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 2007. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that insurance proceeds received by the Corporation for any loss or damage will be fully adequate to compensate for losses incurred.

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 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, PP&E, goodwill, asset retirement obligations, income taxes, employee future benefits, and financial instruments *(Notes 1(C), (F), (G), (I), (L), (M), and (O), respectively)*. Each policy involves a number of estimates and assumptions to be made about matters that are highly 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 A&R Committee and our independent auditors. The A&R Committee 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, 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 statements of earnings. 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 balance sheets as risk management assets or liabilities. Non-derivative contracts are accounted for using the accrual method with changes in fair value being recorded in the Statements of Other Comprehensive Income and are presented on the 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 have quoted market prices or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. These derivatives require the use of internal valuation techniques or models (mark-to-model accounting).

Mark-to-model accounting is currently used for physical and financial forward contracts and option contracts on transmission and transmission congestion. Accrual accounting is used for transmission rights acquired to sell production from our plants and physical transmission rights used by the COD segment. Changes in fair value of derivatives subsequent to inception are recorded on the consolidated balance sheets as price risk management assets or liabilities with the offset recorded in revenues. The values can be favourable or unfavourable, and depending on current market conditions, values can fluctuate significantly with the effect of changes being recorded through earnings in the period of the change. Modelling techniques require us to model future prices, price correlation, market volatility, liquidity, and other forecasted market intelligence, as well as the use of mathematical extrapolation techniques. Where appropriate, the estimates used to derive fair value reflect the potential impact for uncertainties in the modelling process, the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions and operational risk. We validate our mark-to-model results by comparing them against settled data. The amounts reported in the financial statements may change as estimates are revised to reflect actual results or new information, changes in market conditions, or other factors, many of which are beyond our control, and may be material.

Key variables used in the models are uncertain. Sensitivities of the valuation, which would have been recorded in earnings in the current year, are as follows:

Factor	Increase or decrease	Approximate impact on earnings and cash flow (after-tax)
Change in volatility	1%	$ 0.3
Change in commodity price	1%	$ 0.8

There have been no significant changes to the modelling techniques in the past three years.

Valuation of PP&E

As at Dec. 31, 2007, PP&E makes up 71.3 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 is recoverable from future undiscounted cash flows. Factors which could indicate that an 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 continually 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 an 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 as events indicate, we perform an impairment review of our plants. As a result of this review, in 2007, there were no material changes. In 2006, we recorded an impairment charge for the Centralia Gas plant as the full book value of this plant was unlikely to be recovered from future cash flows due to changes in outlook for dispatch rates and trading values and their impact on plant profitability (for further discussion please refer to the Significant Events of this MD&A). From the results of our current impairment review, had assumptions been made that resulted in future cash flows of the plants declining by 10 per cent, none of our plants would have been impaired at Dec. 31, 2007.

As a result of the decision to cease mining activities at the Centralia coal mine, we wrote down mining and reclamation equipment as well as mining infrastructure to the lower of net book value and fair value. For further discussion please refer to the 'Significant Events' section of this MD&A.

In 2005, we determined that the Ottawa plant was impaired in the accounts of TA Cogen. A fundamental shift in the gas markets and forecast increases in the cost of natural gas lowered expected margins from the Ottawa plant as TA Cogen does not have a gas supply contract in place for the period 2008 – 2012 to match the contract to provide electricity under predetermined prices to the Ontario Electricity Financial Corporation ("OEFC"). Based upon the current view of gas costs and market conditions for that period and the likelihood that the plant will not operate as extensively beyond 2012, a reduction in the carrying value was required and a charge of $36.2 million was recognized in 2005. For further discussion please refer to the 'Significant Events' section of this MD&A.

Asset Retirement Obligations ("ARO")

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, 2007, the ARO recorded on the consolidated balance sheets were $276.2 million. We estimate the undiscounted amount of cash flow required to settle the ARO is approximately $0.8 billion, which will be incurred between 2008 and 2072. The majority of the costs will be incurred between 2020 and 2030. A 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 earnings and cash flow (after-tax)
Discount rate	1%	$ 1.9
Undiscounted ARO	1%	$ 0.1

Useful Life of PP&E

PP&E is depreciated over its estimated useful life. Estimated useful lives were 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.

Depreciation and amortization expense was $405.9 million in 2007, of which $32.8 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 $20.3 million in depreciation and amortization expense (2006 – $19.2 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 Merchant Energy Group of the Americas, Vision Quest, and CE Gen. At Dec. 31, 2007, this goodwill had a total carrying value of $124.9 million. The change in value from Dec. 31, 2006 is due to changes in foreign exchange rates.

We reviewed the recorded value of goodwill 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 and therefore no impairment charges were recorded.

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 $342.7 million have been recorded on the consolidated balance sheets at Dec. 31, 2007 (2006 – $319.8 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 $648.7 million have been recorded on the consolidated balance sheets at Dec. 31, 2007 (2006 – $718.5 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 based on all information currently available. The outcome of the 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 2008.

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, 2007, the plan assets had a return of $10.4 million compared to a return of $35.5 million in 2006 and $43.9 million in 2005. The 2007 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2006 and 2005.

Future Accounting Changes

Financial Instruments – Disclosures and Presentation

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

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

International Financial Reporting Standards ("IFRS")

On Feb. 13, 2008, the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. The AcSB has confirmed that Canadian firms will need to begin reporting under IFRS by Jan. 1, 2011 with appropriate comparative data from the prior year. Under IFRS, the primary audience is capital markets and as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy that must be addressed.

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

The impact of these new standards on our financial statements is currently being assessed.

Deferral of Costs and Internally Developed Intangibles

In November 2007, the AcSB approved Section 3064, *Goodwill and Intangible Assets,* replacing Section 3062, *Goodwill and Other Intangible Assets,* and Section 3450, *Research and Development Costs.* Section 3064 incorporates material from IAS 38, *Intangible Assets,* addressing when an internally developed intangible asset meets the criteria for recognition as an asset. The AcSB also approved amendments to Section 1000, *Financial Statement Concepts,* and Accounting Guideline AcG-11, *Enterprises in the Development Stage.* The amendments to AcG-11 provide consistency with Section 3064. EIC-27, *Revenues and Expenditures during the Pre-operating Period*, will not apply to entities that have adopted Section 3064. These changes are effective for us on Jan. 1, 2009, and the impact on our financial statements is currently being assessed.

Embedded Foreign Currency Derivatives

On Jan. 8, 2008, the CICA emerging issues committee issued EIC-169, *Determining whether a contract is routinely denominated in a single currency.* The EIC is intended to provide guidance on when an embedded foreign currency derivative would require bifurcation from a host contract. EIC-169 is effective for us on Jan. 1, 2008 with retrospective application, and is currently not anticipated to have a material impact on our financial statements.

Future Accounting Changes – Early Adopted

Capital Disclosure

On Dec. 1, 2006, the CICA issued Handbook Section 1535, *Capital Disclosures,* which specifies the disclosure of (i) an entity's objectives, policies, and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. We have early adopted this standard. This standard did not have a material effect on our financial statements.

Inventories

In March 2007, the CICA issued Handbook Section 3031, *Inventories,* which aligns accounting for inventories under Canadian GAAP with IFRS. We have early adopted this standard. This standard did not have a material effect on our financial statements.

Non-GAAP Measures

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

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

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

Year ended Dec. 31	2007	2006	2005
Gross margin	**$ 1,544.0**	$ 1,491.4	$ 1,442.0
Operating expenses	**(1,002.9)**	(1,012.9)	(985.2)
Operating income before mine closure and asset impairment charges	**541.1**	478.5	456.8
Mine closure charges	**–**	(191.9)	–
Asset impairment charges	**–**	(130.0)	(36.2)
Operating income	**541.1**	156.6	420.6
Foreign exchange (loss) gain	**3.2**	(0.5)	1.3
Gain on sale of equipment	**15.7**	–	–
Net interest expense	**(133.3)**	(168.5)	(188.6)
Equity (loss) / income	**(49.5)**	(17.0)	(0.9)
Earnings before non-controlling interests and income taxes	**377.2**	(29.4)	232.4
Non-controlling interests	**48.0**	51.5	18.5
Earnings before income taxes	**329.2**	(80.9)	213.9
Income tax (recovery) / expense	**20.4**	(125.8)	39.6
Earning from continuing operations	**308.8**	44.9	174.3
Earning from discontinued operations, net of tax	**–**	–	12.0
Net earnings	**$ 308.8**	$ 44.9	$ 186.3

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results.

In calculating comparable earnings for 2007, we have excluded the gains recorded on the sale of assets at the previously operated Centralia coal mine as we do not normally dispose of large quantities of fixed assets.

In arriving at comparable earnings for 2006 we have excluded the turbine impairment charge recorded in the first quarter of 2006.

For both years we have excluded the impact of the tax rate changes, resolution of outstanding uncertain tax positions, and the tax law change in Mexico as they do not relate to current period earnings.

Year ended Dec. 31	2007	2006	2005
Earnings on a comparable basis	**$ 264.3**	$ 233.8	$ 161.3
Sale of assets at Centralia	**10.2**	–	–
Change in life of Centralia parts, net of tax	**(3.6)**	–	–
Change in tax law in Mexico	**(28.2)**	–	–
Tax rate change	**47.7**	55.3	–
Turbine impairment, net of tax	**–**	(6.2)	–
Recovery from resolution of uncertain tax positions	**18.4**	–	–
Centralia Gas impairment, net of tax	**–**	(84.4)	–
Centralia coal mine writedown, net of tax	**–**	(153.6)	–
Earnings from discontinued operations	**–**	–	12.0
Tax settlement on deferred receivable	**–**	–	13.0
Net earnings	**$ 308.8**	$ 44.9	$ 186.3
Weighted average common shares outstanding in the period	**202.5**	200.8	196.8
Earnings on a comparable basis per share	**$ 1.31**	$ 1.16	$ 0.82

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

The payment of Centralia coal mine closure costs have also been excluded as they are one-time in nature. Sustaining capital expenditures represents total capital expenditures per the statement of cash flow less the amount we have invested in growth projects for the year ended Dec. 31, 2007.

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

Year ended Dec. 31	2007	2006	2005
Cash flow from operating activities	**$ 847.2**	$ 489.6	$ 619.8
Add (Deduct):			
Sustaining capital expenditures	**(417.1)**	(213.7)	(286.5)
Dividends on common shares	**(204.8)**	(133.9)	(79.6)
Distribution to subsidiaries' non-controlling interest	**(86.5)**	(74.4)	(77.5)
Non-recourse debt repayments	**(47.7)**	(51.3)	(36.1)
Timing of contractually scheduled payments	**–**	185.0	–
Centralia coal mine closure costs	**24.2**	–	–
Cash flows from equity investments	**(4.3)**	28.6	19.6
Free cash flow	**$ 111.0**	$ 229.9	$ 159.7

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

Comparable ROCE measures economic value created from capital investments and is calculated by taking comparable earnings before tax and dividing by total assets less current liabilities. 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 tax is presented below:

Year ended Dec. 31	2007	2006	2005
Earnings (loss) before income taxes as per statement of earnings	**$ 329.2**	$ (80.9)	$ 213.9
Net interest expense	**133.3**	168.5	188.6
Non-controlling interest	**48.0**	51.5	18.5
Mine closure charges and inventory writedown, pre-tax	**–**	236.3	–
Asset impairment charges, pre-tax	**–**	130.0	–
Turbine impairment, pre-tax	**–**	9.2	–
Change in life of Centralia parts, pre-tax	**5.5**	–	–
Sale of assets at Centralia	**(15.7)**	–	–
Change in tax law in Mexico	**28.2**	–	–
Comparable earnings, pre-tax	**$ 528.5**	$ 514.6	$ 421.0

Selected Quarterly Information

(in millions of Canadian dollars except per share amounts)	Q1 2007	Q2 2007	Q3 2007	Q4 2007
Revenue	**$ 668.6**	**$ 611.6**	**$ 711.6**	**$ 782.9**
Net earnings	**56.2**	**57.2**	**65.9**	**129.5**
Basic earnings per common share	**0.28**	**0.28**	**0.33**	**0.64**
Diluted earnings per common share	**0.28**	**0.28**	**0.33**	**0.64**
	Q1 2006	Q2 2006	Q3 2006	Q4 2006
Revenue	$ 689.3	$ 580.3	$ 656.0	$ 752.0
Net earnings (loss)	69.2	86.4	35.3	(146.0)
Basic earnings (loss) per common share	0.35	0.43	0.18	(0.72)
Diluted earnings (loss) per common share	0.35	0.43	0.18	(0.72)

Controls and Procedures

As required by Rule 13a-15 under the *Securities Exchange Act* of 1934, management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2007, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

Forward-Looking Statements

This MD&A and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on TransAlta Corporation's beliefs and assumptions based on information available at the time the assumption was made. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. The forward-looking statements relate to, among other things, statements regarding the anticipated business prospects and financial performance of TransAlta. These statements are not guarantees of TransAlta's future performance and are subject to risks, uncertainties, and other important factors that could cause the Corporation's actual performance to be materially different from those projected, including those material risks and assumptions discussed in this MD&A under the headings 'Outlook' and 'Business Environment' in our annual report for the year ended Dec. 31, 2007 under the heading 'Risk Factors and Risk Management'. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues; costs associated with environmental compliance; overall costs; cost and availability of fuel to produce electricity; the speed and degree of competition entering the market; plant availability; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions where TransAlta Corporation operates; results of financing efforts; changes in counterparty risk; and the impact of accounting standards issued by Canadian standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements that are given as of the date it is expressed in this MD&A or otherwise and TransAlta undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

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 in the preparation of 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 Company 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 carried out its responsibility principally through its Audit and Risk 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 Audit and Risk 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
Executive Vice-President & Chief Financial Officer

February 26, 2008

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 into the process safeguards 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 but through commercial agreements, representation on boards of directors of these joint ventures, and through our daily interactions, management is able to assess that key financial and commercial transactions are occurring properly. 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 2007 Consolidated Financial Statements of TransAlta Corporation included $1,477.0 million and $706.6 million of total and net assets, respectively, as of Dec. 31, 2007, and $491.4 million and $95.7 million of revenues and operational earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at Dec. 31, 2007, 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, 2007, 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 page 71 of this Annual Report.

STEPHEN G. SNYDER
President & Chief Executive Officer

BRIAN BURDEN
Executive Vice-President & Chief Financial Officer

February 26, 2008

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, 2007, 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 performs 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 company'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 company'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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company'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 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, included in the Corporation's 2007 consolidated financial statements and constituting $1,477.0 million and $706.6 million of total and net assets, respectively, as at December 31, 2007, and $491.4 million and $95.7 million of revenues and 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 controls over financial reporting of these joint ventures.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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 balance sheets of TransAlta Corporation as at December 31, 2007 and 2006 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, 2007, and our report dated February 26, 2008, expressed an unqualified opinion thereon.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
February 26, 2008

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, 2007 and 2006 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, 2007. 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 disclosure 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, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in conformity with Canadian generally accepted accounting principles.

As discussed in *Note 1 (T)* to the consolidated financial statements, in 2007 the Corporation changed its method of accounting for inventories, 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, 2007, 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 26, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

Calgary, Canada
February 26, 2008

Consolidated Statements of Earnings and Retained Earnings

Year ended Dec. 31 *(in millions of Canadian dollars)*	2007	2006	2005
		(Restated, Note 1)	*(Restated, Note 1)*
Revenues *(Note 1)*	$ 2,774.7	$ 2,677.6	$ 2,664.4
Fuel and purchased power *(Notes 1 and 2)*	(1,230.7)	(1,186.2)	(1,222.4)
Gross margin	1,544.0	1,491.4	1,442.0
Operations, maintenance and administration	576.8	581.3	596.0
Depreciation and amortization *(Note 1)*	405.9	410.3	367.9
Taxes, other than income taxes	20.2	21.3	21.3
Operating expenses	1,002.9	1,012.9	985.2
Mine closure charges *(Note 2)*	–	191.9	
Asset impairment charges *(Note 3)*	–	130.0	36.2
Operating income	541.1	156.6	420.6
Foreign exchange gain (loss)	3.2	(0.5)	1.3
Gain on sale of equipment *(Note 14)*	15.7	–	–
Net interest expense *(Note 19)*	(133.3)	(168.5)	(188.6)
Equity loss *(Note 11)*	(49.5)	(17.0)	(0.9)
Earnings (loss) before non-controlling interests and income taxes	377.2	(29.4)	232.4
Non-controlling interests *(Note 22)*	48.0	51.5	18.5
Earnings (loss) before income taxes	329.2	(80.9)	213.9
Income tax expense (recovery) *(Note 4)*	20.4	(125.8)	39.6
Earnings from continuing operations	308.8	44.9	174.3
Earnings from discontinued operations, net of tax *(Note 5)*	–	–	12.0
Net earnings	$ 308.8	$ 44.9	$ 186.3
Retained earnings			
Opening balance	710.0	866.1	876.7
Common share dividends	(202.5)	(201.0)	(196.9)
Shares cancelled under NCIB *(Note 24)*	(53.8)	–	–
Closing balance	$ 762.5	$ 710.0	$ 866.1
Weighted average number of common shares outstanding in the period	202.5	200.8	196.8
Basic and diluted earnings per share *(Note 23)*			
Net earnings from continuing operations	$ 1.53	$ 0.22	$ 0.88
Earnings from discontinued operations	–	–	0.06
Net earnings per share, basic and diluted	$ 1.53	$ 0.22	$ 0.94

See accompanying notes.

Consolidated Balance Sheets

Dec. 31 *(in millions of Canadian dollars)*	2007	2006
## Assets		*(Restated, Note 1)*
Current assets		
Cash and cash equivalents	$ 50.9	$ 65.6
Accounts receivable *(Notes 6, 27 and 28)*	546.4	618.3
Prepaid expenses	8.9	9.1
Risk management assets *(Notes 1, 7 and 8)*	93.2	72.2
Future income tax assets *(Note 4)*	40.2	25.8
Income taxes receivable	48.8	47.6
Inventory *(Note 9)*	30.1	53.0
Current portion of other assets *(Note 17)*	–	5.4
	818.5	897.0
Restricted cash *(Note 10)*	242.4	347.8
Investments *(Note 11)*	124.6	154.5
Long-term receivables *(Note 12)*	5.6	32.2
Property, plant and equipment *(Note 13)*		
Cost	8,592.7	8,248.9
Accumulated depreciation and amortization	(3,475.4)	(3,207.0)
	5,117.3	5,041.9
Assets held for sale, net *(Note 14)*	29.1	109.8
Goodwill *(Notes 15 and 31)*	124.9	137.5
Intangible assets *(Note 16)*	209.2	292.1
Future income tax assets *(Note 4)*	302.5	294.0
Risk management assets *(Notes 1, 7 and 8)*	122.0	65.1
Other assets *(Notes 1 and 17)*	82.6	88.2
Total assets	$ 7,178.7	$ 7,460.1
## Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt *(Note 18)*	$ 650.8	$ 361.9
Accounts payable and accrued liabilities *(Notes 28 and 33)*	472.1	441.9
Risk management liabilities *(Notes 1, 7 and 8)*	105.1	32.4
Income taxes payable	17.2	22.3
Future income tax liabilities *(Note 4)*	12.0	19.9
Dividends payable	49.3	51.5
Current portion of long-term debt – recourse *(Notes 7 and 19)*	121.5	205.0
Current portion of long-term debt – non-recourse *(Notes 7 and 19)*	32.3	44.7
Current portion of asset retirement obligations *(Note 20)*	42.8	48.5
Preferred securities *(Note 19)*	–	175.0
	1,503.1	1,403.1
Long-term debt – recourse *(Notes 7 and 19)*	1,496.2	1,681.5
Long-term debt – non-recourse *(Notes 7 and 19)*	209.3	289.6
Asset retirement obligations *(Note 20)*	233.4	280.0
Deferred credits and other long-term liabilities *(Notes 1 and 21)*	100.9	130.4
Future income tax liabilities *(Note 4)*	636.7	698.6
Risk management liabilities *(Notes 1, 7 and 8)*	204.2	14.0
Non-controlling interests *(Note 22)*	496.4	535.0
Shareholders' equity		
Common shares *(Note 23 and 24)*	1,780.8	1,782.4
Retained earnings *(Note 24)*	762.5	710.0
Accumulated other comprehensive loss *(Notes 1 and 24)*	(244.8)	(64.5)
Total shareholders' equity	2,298.5	2,427.9
Total liabilities and shareholders' equity	$ 7,178.7	$ 7,460.1

Contingencies *(Notes 27, 28 and 30)*

Commitments *(Notes 8, 28 and 29)*

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)*	2007	2006	2005
Net earnings	**$ 308.8**	$ 44.9	$ 186.3
Other comprehensive income / (loss)			
(Losses) gains on translating net assets of self-sustaining foreign operations	**(196.2)**	3.6	(61.2)
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations	**240.7**	(1.5)	54.2
Tax expense (recovery)	**25.4**	(0.3)	7.8
	215.3	(1.2)	46.4
Gains (losses) on translation of self-sustaining foreign operations	**19.1**	2.4	(14.8)
Losses on derivatives designated as cash flow hedges	**(56.7)**	–	–
Tax recovery	**(15.9)**	–	–
Losses on derivatives designated as cash flow hedges	**(40.8)**	–	–
Derivatives designated as cash flow hedges in prior periods transferred to balance sheet in the current period	**0.7**	–	–
Derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period	**25.2**	–	–
Tax expense	**7.2**	–	–
	18.7	–	–
Other comprehensive (loss) income	**(3.0)**	2.4	(14.8)
Comprehensive income	**$ 305.8**	$ 47.3	$ 171.5

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	2007	2006	2005
Operating activities			
Net earnings	$ 308.8	$ 44.9	$ 186.3
Depreciation and amortization *(Note 31)*	415.1	437.8	400.9
Gain on sale of equipment *(Note 14)*	(15.7)	–	–
Non-controlling interests *(Note 22)*	48.0	51.5	18.5
Asset retirement obligation accretion *(Note 20)*	23.6	21.5	19.3
Asset retirement costs settled *(Note 20)*	(38.4)	(29.2)	(29.4)
Future income taxes *(Note 4)*	(33.8)	(163.7)	5.6
Unrealized (gains) losses from risk management activities	26.3	(32.2)	4.9
Foreign exchange (gain) loss	(3.2)	0.5	(1.3)
Mine closure charges *(Note 2)*	–	191.9	–
Asset impairment charges *(Note 3)*	–	130.0	36.2
Equity loss *(Note 11)*	49.5	17.0	0.9
Other non-cash items	1.3	8.8	(3.0)
	781.5	678.8	638.9
Change in non-cash operating working capital balances	65.7	(189.2)	(19.1)
Cash flow from operating activities	847.2	489.6	619.8
Investing activities			
Additions to property, plant and equipment	(599.1)	(223.7)	(325.9)
Proceeds on sale of property, plant and equipment *(Note 14)*	46.9	29.4	1.6
Equity investment *(Note 11)*	(19.6)	226.4	(9.3)
Restricted cash *(Note 10)*	56.8	(333.1)	2.3
Acquisition of Wailuku Hydro facility *(Note 26)*	–	(1.2)	–
Realized gains on financial instruments	107.0	53.9	89.8
Proceeds on sale of long-term investments	–	3.0	–
Other	(2.1)	(16.0)	(1.0)
Cash flow used in investing activities	(410.1)	(261.3)	(242.5)
Financing activities			
Increase (decrease) in short-term debt	288.9	348.1	(23.6)
Issuance of long-term debt *(Note 19)*	30.3	–	–
Repayment of long-term debt *(Note 19)*	(251.9)	(396.7)	60.7
Dividends paid on common shares	(204.8)	(133.9)	(99.2)
Redemption of preferred securities *(Note 19)*	(175.0)	–	(300.0)
Funds paid to repurchase common shares under NCIB *(Note 24)*	(74.9)	–	–
Net proceeds on issuance of common shares *(Note 23)*	19.5	12.9	19.6
Distributions to subsidiaries' non-controlling interests	(86.5)	(74.4)	(77.5)
Decrease (increase) in advances to TransAlta Power	6.1	0.8	23.7
Other	4.5	–	–
Cash flow used in financing activities	(443.8)	(243.2)	(396.3)
Cash flow used in operating, investing and financing activities	(6.7)	(14.9)	(19.0)
Effect of translation on foreign currency cash	(8.0)	1.2	(2.9)
Decrease in cash and cash equivalents	(14.7)	(13.7)	(21.9)
Cash and cash equivalents, beginning of year	65.6	79.3	101.2
Cash and cash equivalents, end of year	$ 50.9	$ 65.6	$ 79.3
Cash taxes paid	$ 75.1	$ 35.6	$ 14.7
Cash interest paid	$ 141.7	$ 181.2	$ 183.7

See accompanying notes.

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

1. Summary of Significant Accounting Policies

A. 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 Corporation ("TransAlta" or "the Corporation"), all subsidiaries, and the proportionate share of the accounts of joint ventures and jointly controlled corporations.

B. Use of Estimates

The preparation of 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 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, 8, 11, 13, 15, 16, 19, 28, and 33)*.

C. 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.

Derivatives used in trading activities are used to earn trading revenues and to gain market information and include physical and financial swaps, forward sales contracts, futures contracts, and options. These derivatives are accounted for using the fair value method of accounting. Derivatives are presented on a net basis on the statement of earnings. 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 balance sheets as risk management assets and liabilities.

The majority of the Corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or the contracts extend beyond the time period for which market-based quotes are available, requiring the use of internal valuation techniques or models ("mark-to-model accounting").

D. Discontinued Operations

The results of discontinued operations are presented net of tax on a one-line basis in the consolidated statements of earnings. Interest expense, direct corporate overheads and income taxes are allocated to discontinued operations. General corporate overheads are not allocated to discontinued operations.

E. Inventory

The majority of cost of goods sold as recorded on the statement 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.

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. Due to the limited amount of processing steps incurred in mining coal 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 is also determined using direct costing which includes all applicable expenditures and charges incurred in bringing inventory to its existing condition and location.

F. 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 sheet 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 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 markets 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 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.

G. Goodwill

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill and certain intangibles are not subject to amortization, but are instead 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 unit to which the goodwill relates or significant negative industry or economic trends. To test for impairment, the fair value of the reporting units to which the goodwill relates is compared to the carrying values of the reporting units. The Corporation determined that the fair values of the reporting units, exceeded their carrying values as at Dec. 31, 2007 and 2006.

H. 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 CE Generation LLC ("CE Gen"), a jointly controlled enterprise *(Note 34)*. Sale contracts are valued at cost and are amortized on a straight-line basis over the remaining applicable contract period, which ranges from two to 27 years.

I. Asset Retirement Obligations ("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 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.

J. Investments

The wholly owned subsidiaries that hold TransAlta's interests in the Campeche and Chihuahua power plants are considered Variable Interest Entities ("VIEs") and are shown as equity investments.

Investments in shares of companies over which the Corporation exercises significant influence are accounted for using the equity method. Other investments are carried at cost. If there is other than a temporary decline in the value of an investment, it is written down to net realizable value.

K. Other Assets

Deferred license fees and deferred contract costs are amortized on a straight-line basis over the useful life of the related assets or long-term contracts.

Other costs capitalized on the balance sheet include project development costs, which includes external, direct and incremental costs which are necessary for completion of an acquisition or construction project. Such 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.

L. Income Taxes

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 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.

M. 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. Past service costs from plan amendments are amortized on a straight-line basis over the Estimated Average Remaining Service Life ("EARSL") of employees active at the date of amendment. 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 is amortized over the estimated average remaining service period of the active employees. 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 EARSL.

N. 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") and 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 foreign currencies are translated at the exchange rate on the transaction date. The resulting exchange gains and losses on these items are included in net earnings.

O. Derivatives and Financial Instruments

To be accounted for as a hedge, a derivative must be designated and documented as a hedge, and must be effective at inception and on an ongoing basis. The documentation 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 includes linking derivatives to specific assets and liabilities on the balance sheet 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. Hedge effectiveness of cash flow hedges are achieved if the derivatives' cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows are similar. Hedge effectiveness of fair values is achieved if changes in the fair value of the derivative substantially offset changes in the fair value of the item hedged. Any ineffective portion in highly effective hedges is recognized in earnings in the current period. If the above hedge criteria are not met, the derivative is accounted for on the balance sheet at fair value, with the initial fair value and subsequent changes in fair value recorded in earnings in the period of change.

If a derivative that has been accorded hedge accounting matures, expires, is sold, terminated or cancelled, the termination gain or loss is deferred and recognized when the gain or loss on the item hedged is recognized. If a designated hedged item matures, expires, is sold, extinguished or terminated, or the hedged item is no longer probable of occurring, any amounts in OCI associated with the hedging item are recognized in current earnings along with the corresponding gains or losses recognized on the hedged item. If a hedging relationship is terminated or ceases to be effective, hedge accounting is not applied to subsequent gains or losses. Any previously deferred amounts are carried forward and recognized in earnings in the same period as the hedged item.

Derivatives used in trading activities are described in *Note 1(C)*.

Physical and financial swaps, forward sales contracts, futures contracts, and options are used in 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 earnings in the same period and financial statement caption as the hedged exposure. Up to the date of settlement, the fair value of the hedges is recorded in risk management assets or liabilities with changes in value being reported in OCI. For those swaps, forwards, futures, and contracts that the Corporation does not seek or is ineligible for hedge accounting, changes in fair value are recorded in earnings.

Cross-currency interest rate swaps, foreign currency forward contracts, and foreign currency debts are used to hedge exposure to changes in the carrying values of the Corporation's net investments in 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. For those instruments that the Corporation does not seek or are ineligible for hedge accounting, changes in fair value are recorded in earnings.

Foreign currency forward contracts are used in cash flow hedges to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. If hedge 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 are included in the cost of the asset or liability when the asset is purchased and depreciated over the asset's estimated useful life.

Interest rate swaps are used to manage the ratio of floating rates 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.

P. Stock-Based Compensation Plans

The Corporation has three types of stock-based compensation plans comprised of two stock option-based plans, and a Performance Share Ownership Plan ("PSOP"), described in *Note 32*. Under the fair value method, compensation expense is measured at the grant date at fair value and recognized over the service period. In 2007, the Corporation did not grant options to its employees.

Stock grants under 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 Standard & Poor's ("S&P")/Toronto Stock Exchange ("TSX") composite index. 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.

Q. Cash and Cash Equivalents

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

R. Accounting for Emission Credits and Allowances

Purchased emission allowances are recorded on the balance sheet 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 emissions liability on the balance sheet 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.

S. Planned Maintenance

Planned maintenance expenditures include both expense and capital portions. Expense portions are expensed in the period incurred. Capitalized amounts are capitalized in the period of maintenance activities and are amortized on a straight-line basis over the life of the asset.

T. Accounting Changes

Depreciation Expense

For active mines, accretion expense is included in fuel and purchased power. However, as the Centralia coal mine is now considered inactive, related accretion expense is included as part of depreciation expense. In 2006 and 2005, $8.7 million and $8.2 million, respectively, was recorded in fuel expense related to accretion expense incurred at the Centralia coal mine.

Change in Estimate of Certain Components at Centralia Thermal

As a result of the Corporation's decision to stop mining at the Centralia coal mine, TransAlta is now procuring all of the coal used in production at Centralia Thermal from several selected third party vendors. The coal that is delivered from these vendors is of a different chemical composition and has a different thermal content than the coal from the Centralia coal mine. Previously, this externally sourced coal was blended with internally produced coal to maximize the output from Centralia Thermal. However, with the cessation of mining, this locally mined coal is no longer available to be blended and therefore the coal being consumed burns at a higher temperature and produces a different composition of ash. The boiler at Centralia Thermal is not currently configured to run optimally at these higher temperatures or with the different ash compositions.

During 2007, test burns were conducted to determine what equipment modifications are needed to be performed to optimize this consumption of third party delivered coal. During 2007, a technical plan was completed including which components needed to be replaced to ensure continued maximum output from Centralia Thermal. These equipment modifications are scheduled to occur during planned maintenance outages in 2008 and 2009. As a result, the estimated useful life of the component parts that are to be replaced during these planned outages has been reduced and this change in estimate of useful life will be recognized over the period up to the related maintenance outage.

As a result, depreciation expense increased $5.5 million in 2007 compared to 2006. In 2008 and 2009 depreciation expense will increase by $13.6 million and $2.6 million, respectively, compared to 2006.

Presentation of Gross Margins

Previously, revenues and related costs for contracts settled in real-time physical markets were recorded on a gross basis. However, all of these contracts are being held for trading, irrespective of the market in which they are settled. Therefore, it is more representative of the actual trading activities of Commercial Operations and Development ("COD") to report the results of these contracts on a net basis.

Consolidated prior year balances have been reclassified to conform with the current year's presentation, as shown below. Consolidated current year balances have been prepared in the following table using previously disclosed methodologies for information purposes only.

Year ended Dec. 31	2007	2006	2005
Revenue – *as previously calculated*	$ 2,992.5	$ 2,796.5	$ 2,838.5
Trading purchases	(217.8)	(118.9)	(174.1)
Revenue – *as revised*	$ 2,774.7	$ 2,677.6	$ 2,664.4

Inventories

In March 2007, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3031, *Inventories*, which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards ("IFRS"). TransAlta early adopted this standard. This standard did not have a material effect on the financial statements *(Note 9)*.

Capital Disclosure

On Dec. 1, 2006, the CICA issued Section 1535, *Capital Disclosures*. TransAlta early adopted this standard and provided the required disclosure in *Note 25*.

General Standards on Financial Statement Presentation

On June 1, 2007, the CICA issued Section 1400, *General Standards on Financial Statement Presentation*. TransAlta early adopted this standard and did not require any additional disclosures.

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 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.

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

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 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 sheet.

Financial Instruments – Recognition and Measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and financial liabilities, including derivatives, be recognized on the consolidated balance sheet when 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 rate method. Financial liabilities are removed from the financial statements when the liability is extinguished either through settlement of or release from the obligation of the underlying liability.

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

Derivative instruments are recorded on the consolidated balance sheet at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net earnings with the exception of the effective portion of (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 rate 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.

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 the hedged anticipated transaction is probable of not occurring.

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

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 earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives were not recorded on the balance sheet. 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 balance sheet. Interest rate swaps used to manage the impact of fluctuating interest rates on existing debt were not recognized on the balance sheet if they met hedge criteria.

Impact upon Adoption of Sections 1530, 3855 and 3865

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

For hedging relationships existing prior to adopting Section 3865 that continue to qualify for hedge accounting under the new standard, the transition accounting is as follows: (i) fair value hedges – any gain or loss on the hedging instrument was recognized in opening retained earnings and the carrying amount of the hedged item was adjusted by the cumulative change in fair value attributable to the designated hedged risk and was also included in opening retained earnings 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 *(Note 24)*.

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

The majority of the changes were reflected in the value of COD risk management assets and liabilities as well as in financial instruments used as hedges of debt and net investment of self-sustaining foreign subsidiaries. The impact of adopting these standards on the Corporation's Jan. 1, 2007 balance sheet is outlined below:

	Price risk assets		Price risk liabilities		
	Current	**Long-term**	**Current**	**Long-term**	**Net**
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 – *as reported* [1]	$ 72.2	$ 65.1	$ (32.4)	$ (14.0)	$ 90.9
Fair value of COD net risk management assets (liabilities) outstanding at Jan. 1, 2007	99.6	77.7	(122.2)	(276.3)	(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Jan. 1, 2007	12.6	61.1	(3.9)	(22.1)	47.7
Total fair values	$ 112.2	$ 138.8	$ (126.1)	$ (298.4)	$ (173.5)

1 *Previously reported balances have been reclassified* (Note 1 (T)).

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

Net risk management assets outstanding at Dec. 31, 2006 – *as reported*	$	90.9
Fair value of COD net risk management liabilities outstanding at Jan. 1, 2007		(221.2)
Fair value of hedges of debt and net investment of foreign subsidiaries at Jan. 1, 2007		47.7
Total fair value of risk management liabilities		(173.5)
Change in fair value		(264.4)
Tax		(87.1)
Adjustment to opening Accumulated Other Comprehensive Loss from fair values	$	(177.3)
Cumulative translation adjustment at Dec. 31, 2006		(64.5)
Opening balance, Accumulated Other Comprehensive Loss	$	(241.8)

Variable Interest Entities ("VIEs")

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

U. Future Accounting Changes

Deferral of Costs and Internally Developed Intangibles

In November 2007, the Accounting Standards Board ("AcSB") approved Section 3064, *Goodwill and Intangible Assets*, replacing Section 3062, *Goodwill and Other Intangible Assets,* and Section 3450, *Research and Development Costs*. Section 3064 incorporates material from IAS 38, *Intangible Assets,* addressing when an internally developed intangible asset meets the criteria for recognition as an asset. The AcSB also approved amendments to Section 1000, *Financial Statement Concepts,* and Accounting Guideline AcG-11, *Enterprises in the Development Stage*. The amendments to AcG-11 provide consistency with Section 3064. EIC-27, *Revenues and Expenditures during the Pre-operating Period,* will not apply to entities that have adopted Section 3064. These changes are effective for TransAlta on Jan. 1, 2009, and the impact on TransAlta's financial statements is currently being assessed.

Embedded Foreign Currency Derivatives

On Jan. 8, 2008, the CICA Emerging Issues Committee issued EIC-169 *Determining whether a contract is routinely denominated in a single currency.* The EIC is intended to provide guidance on when an embedded foreign currency derivative would require bifurcation from a host contract. EIC-169 is effective for TransAlta on Jan. 1, 2008 with retrospective application, and is currently not anticipated to have a material impact on TransAlta's financial statements.

Financial Instruments – Disclosures and Presentation

On Dec. 1, 2006, the CICA issued Handbook Section 3862, *Financial Instruments – Disclosures,* and Handbook Section 3863, *Financial Instruments – Presentation.* These new standards were effective on Jan. 1, 2008 and replace Handbook Section 3861, *Financial Instruments – Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks.

The impact of these new standards on TransAlta's financial statements is currently being assessed.

International Financial Reporting Standards

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. On Feb. 13, 2008, the AcSB had confirmed that the use of IFRS will be required by Jan. 1, 2011, with appropriate comparative data from the prior year. Under IFRS, the primary audience is capital markets and as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy that must be addressed.

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

The impact of these new standards on TransAlta's financial statements is currently being assessed.

2. Mine Closure Charges

On Nov. 27, 2006, TransAlta ceased mining activities at the Centralia coal mine as a result of increased costs and unfavourable geological conditions. All associated mining and reclamation equipment was written down to the lower of net book value or anticipated realized proceeds. Mine infrastructure, including coal processing equipment and structures, haul roads, and other equipment were written down to anticipated net salvage value. Asset retirement costs, representing the unamortized cost of future reclamation, were also written off. In addition, employee termination costs and other miscellaneous expenses were recorded. The total of these write-downs and provisions before taxes was $191.9 million.

As a result of the cessation of mining activities, all internally produced coal was also written down to fair market value, which is replacement cost, resulting in an expense of $44.4 million being recorded in fuel and purchased power. The total amounts are summarized in the table below:

Writedown of coal inventory	$ 44.4
Impact on gross margin	(44.4)
Mine closure charges	
Mine equipment and infrastructure writedown	72.1
ARO writedown	81.3
Severance costs and other	38.5
Total mine closure charges	191.9
Loss before income taxes	$ (236.3)
Income tax recovery	82.7
Net loss impact of event	$ (153.6)

3. Asset Impairment Charges

For the year ended Dec. 31, 2006, changes in the outlook for dispatch rates and trading values and their impact on plant profitability resulted in the determination that the full book value of the Centralia Gas facility was unlikely to be recovered from future cash flows. As a result of a market valuation, TransAlta recorded a $130.0 million pre-tax impairment charge to write this plant down to its fair value. This asset is included in the Generation segment.

For the year ended Dec. 31, 2005, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, recorded an impairment charge of $78.3 million in respect of the Ottawa facility as the net book value of that facility exceeded its net recoverable amount, measured as the future cash flows from the facility. The net book value of the Ottawa facility in the accounts of the Corporation is lower than that in TA Cogen. The carrying value in TransAlta is fully recoverable from future cash flows of the facility. The difference in net book value between the accounts of the Corporation and TA Cogen is due to the higher purchase price of the plant paid by TA Cogen. The Corporation has recognized an increase in depreciation expense of $36.2 million related to TransAlta Power, L.P.'s share of the impairment charge. This amount is offset by a recovery in the earnings attributable to non-controlling interests in the Corporation's income statement.

4. 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's operations are complex, and the computation and provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. The Corporation's tax filings are subject to audit by taxation authorities. 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.

A. Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2007	2006	2005
		(Restated, Note 1)	*(Restated, Note 1)*
Earnings (loss) from continuing operations before income taxes	**$ 329.2**	$ (80.9)	$ 213.9
Equity loss	**(49.5)**	(17.0)	(0.9)
Earnings (loss) before income taxes and excluding equity loss	**$ 378.7**	$ (63.9)	$ 214.8
Statutory Canadian federal and provincial income tax rate (%)	**32.1**	32.5	33.6
Expected taxes (recovery) on income	**121.6**	(20.8)	72.2
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(35.9)**	(32.9)	(28.0)
Asset impairment and mine closure charges recognized at higher tax rate	**–**	(9.2)	–
Resolution of uncertain tax positions, net	**(18.4)**	–	(13.0)
Capital taxes	**2.0**	3.2	10.0
Effect of tax rate changes	**(47.7)**	(55.3)	–
Statutory and other rate differences	**(1.4)**	(4.4)	3.3
Other	**0.2**	(6.4)	(4.9)
Income tax expense (recovery)	**$ 20.4**	$ (125.8)	$ 39.6
Effective tax rate (%)	**5.4**	196.9	18.4

To present comparable reconciliations, prior years' effective tax rate analysis were reclassified and calculated on earnings (loss) before income tax and excluding equity loss *(Note 11)*.

II. Components of Income Tax Expense (Recovery)

Year ended Dec. 31	2007	2006	2005
Current tax expense	$ 54.2	$ 37.9	$ 34.0
Future income tax expense (recovery) related to the origination and reversal of temporary differences	13.9	(108.4)	9.4
Future income tax recovery resulting from changes in tax rates or laws	(47.7)	(55.3)	(3.8)
Income tax expense (recovery)	**$ 20.4**	**$ (125.8)**	**$ 39.6**

B. Balance Sheets

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

As at Dec. 31	2007	2006
Net operating and capital loss carryforwards	$ 178.1	$ 255.4
Future site restoration costs	77.3	79.5
Property, plant and equipment	(717.1)	(803.6)
Risk management assets and liabilities	75.3	(23.2)
Employee future benefits and compensation plans	21.2	26.5
Allowance for doubtful accounts	18.0	21.3
Other deductible temporary differences	41.2	45.4
Future income tax (liabilities) and assets	**$ (306.0)**	**$ (398.7)**

Presented in the balance sheet as follows:

As at Dec. 31	2007	2006
Assets		
Current	$ 40.2	$ 25.8
Long-term	302.5	294.0
Liabilities		
Current	(12.0)	(19.9)
Long-term	(636.7)	(698.6)
Future income tax (liabilities) and assets	**$ (306.0)**	**$ (398.7)**

As at Dec. 31, 2007, there were income tax loss carryforwards of $61.3 million (2006 – $37.5 million) for which no tax benefit has been recognized. These losses begin to expire in 2013.

5. Discontinued Operations

In August 2000, the Corporation sold its Alberta Distribution and Retail ("D&R") business. During 2005, the Corporation settled an outstanding income tax dispute related to this business.

6. Accounts Receivable

As at Dec. 31	2007	2006
Gross accounts receivable	$ 591.9	$ 672.2
Allowance for doubtful accounts *(Note 30)*	(45.5)	(53.9)
Net accounts receivable	**$ 546.4**	**$ 618.3**

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2006	$ 53.9
Change in foreign exchange rates	(8.4)
Balance, Dec. 31, 2007	**$ 45.5**

7. Fair Values of Financial Instruments

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

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

A. Accounting for Changes in Fair Value of Financial Instruments During the Period

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

Carrying Value and Fair Value of Selected Financial Instruments

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

Carrying value and fair value of financial instruments as at Dec. 31, 2007	Classified as held-for-trading	Derivatives used for hedging	Per consolidated balance sheet	Total fair value
Risk management assets				
Current	$ 24.0	$ 69.2	$ 93.2	$ 93.2
Long-term	0.4	121.6	122.0	122.0
Total risk management assets	$ 24.4	$ 190.8	$ 215.2	$ 215.2
Risk management liabilities				
Current	$ 12.4	$ 92.7	$ 105.1	$ 105.1
Long-term	13.5	190.7	204.2	204.2
Total risk management liabilities	$ 25.9	$ 283.4	$ 309.3	$ 309.3

Carrying value and fair value of financial instruments as at Dec. 31, 2006	Classified as held-for-trading	Derivatives used for hedging	Per consolidated balance sheet	Total fair value [1]
Risk management assets				
Current	$ 61.0	$ 11.2	$ 72.2	$ 112.2
Long-term	21.9	43.2	65.1	138.8
Total risk management assets	$ 82.9	$ 54.4	$ 137.3	$ 251.0
Risk management liabilities				
Current	$ 30.3	$ 2.1	$ 32.4	$ 126.1
Long-term	11.8	2.2	14.0	298.4
Total risk management liabilities	$ 42.1	$ 4.3	$ 46.4	$ 424.5

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

B. Hedging Activities

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

Fair Value Hedges

Interest rate swaps are used to hedge exposures to the changes in a fixed interest rate instrument's fair value caused by changes in interest rates. Foreign exchange contracts are also used to hedge foreign currency denominated assets and liabilities. See *Note 19* for a further description of the terms and rates of these swaps.

No ineffective portion of fair value hedges was recorded in 2007, 2006 and 2005.

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, 2007, a pre-tax unrealized loss of $56.7 million was recorded in OCI for the effective portion of the cash flow hedges, and an unrealized pre-tax gain of $25.2 million was reclassified to net income. No net unrealized gain or loss was recognized in income for the ineffective portion.

At Dec. 31, 2006, the Corporation's cash flow hedges of the forecasted sales and the forecasted purchases for the Corporation's generating facilities were accounted for using settlement accounting.

Over the next 12 months, the Corporation estimates that $43.8 million of after-tax losses will be reclassified from AOCI to 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. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings, either positive or negative, will be for the next 12 months. These contracts have a maximum duration of five years (*Note 8*).

Net Investment Hedges

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

For the year ended Dec. 31, 2007, the net after-tax gain of $19.1 million (2006 – $2.4 million gain, 2005 – $14.8 million loss) relating to the net investment in foreign operations, net of hedging, was recognized in OCI.

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

	Fair value hedges	Cash flow hedges	Net investment hedges	Not designated in a hedging relationship	Total
Financial assets					
Derivative instruments	$ 12.5	$ 17.7	$ 160.6	$ 24.4	$ 215.2
Financial liabilities					
Derivative instruments	$ –	$ (282.9)	$ (0.5)	$ (25.9)	$ (309.3)

U.S. dollar denominated debt with a face value of U.S.$600 million has also been designated as a part of the hedge of TransAlta's self-sustaining foreign operations.

8. Risk Management Assets and Liabilities

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

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

As at Dec. 31	2007			2006		
Balance Sheet – Totals	Energy Trading	Other	Total	Energy Trading	Other	Total
Risk management assets						
Current	$ 34.0	$ 59.2	$ 93.2	$ 61.0	$ 11.2	$ 72.2
Long-term	(4.1)	126.1	122.0	21.9	43.2	65.1
Risk management liabilities						
Current	(86.5)	(18.6)	(105.1)	(30.3)	(2.1)	(32.4)
Long-term	(192.5)	(11.7)	(204.2)	(1.0)	(13.0)	(14.0)
Net risk management (liabilities) assets outstanding	$ (249.1)	$ 155.0	$ (94.1)	$ 51.6	$ 39.3	$ 90.9

A. 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	2007			2006
Balance Sheet – Energy Trading	Hedges	Non-hedges	Total	Total related to Energy Trading
Risk management assets				
Current	$ 12.3	$ 21.7	$ 34.0	$ 61.0
Long-term	(4.5)	0.4	(4.1)	21.9
Risk management liabilities				
Current	(76.7)	(9.8)	(86.5)	(30.3)
Long-term	(191.9)	(0.6)	(192.5)	(1.0)
Net risk management (liabilities) assets outstanding	$ (260.8)	$ 11.7	$ (249.1)	$ 51.6

The following table illustrates the impact of adopting new standards for financial instruments *(Note 1(T))* and the movements in the fair value of the Corporation's Energy Trading net risk management assets and liabilities separately by source of valuation during 2007:

	Hedges		Non-hedges		
Change in fair value of net assets (liabilities)	**Fair value (market)**	**Fair value (model)**	**Fair value (market)**	**Fair value (model)**	**Total**
Net risk management assets (liabilities) outstanding at Dec. 31, 2006 – *as reported*	$ –	$ –	$ 52.7	$ (1.1)	$ 51.6
Net risk management liabilities outstanding at Jan. 1, 2007 – *fair value* [1]	(253.0)	(19.8)	52.7	(1.1)	(221.2)
Contracts realized, amortized or settled during the period	47.9	4.5	(31.9)	(3.9)	16.6
Changes in values attributable to market price and other market changes	(59.9)	0.9	19.9	(1.8)	(40.9)
New contracts entered into during the current period	(21.6)	–	(9.2)	8.6	(22.2)
Changes in foreign exchange values	22.9	–	(4.1)	(0.2)	18.6
Changes in values attributable to discontinued hedge treatment of certain contracts	17.3	–	(17.3)	–	–
Net risk management (liabilities) assets outstanding at Dec. 31, 2007 – *fair value*	**$ (246.4)**	**$ (14.4)**	**$ 10.1**	**$ 1.6**	**$ (249.1)**

1 *As a result of adopting new accounting standards* (Note 1(T)).

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:

	2008	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**	**Total**
Hedges							
Fair value based on market prices	$ (61.1)	$ (92.8)	$ (65.6)	$ (25.8)	$ (1.1)	$ –	$ (246.4)
Fair value based on models	(3.9)	(5.3)	(3.9)	(1.3)	–	–	(14.4)
	$ (65.0)	$ (98.1)	$ (69.5)	$ (27.1)	$ (1.1)	$ –	$ (260.8)
Non-hedges							
Fair value based on market prices	$ 9.8	$ 0.3	$ –	$ –	$ –	$ –	$ 10.1
Fair value based on models	2.0	(0.4)	–	–	–	–	1.6
	$ 11.8	(0.1)	–	–	–	–	11.7
Total	$ (53.2)	$ (98.2)	$ (69.5)	$ (27.1)	$ (1.1)	$ –	$ (249.1)

The Corporation's fixed price proprietary trading positions at Dec. 31, 2007 and Dec. 31, 2006, were as follows:

Units (000s)	**Electricity (MWh)**	**Natural gas (GJ)**	**Transmission (MWh)**	**Coal (tonnes)**	**Emissions (tonnes)**
Fixed price payor, notional amounts, Dec. 31, 2007	**16,189**	**54,523**	**1,854**	**1,644**	**6**
Fixed price payor, notional amounts, Dec. 31, 2006	13,944	20,289	1,479	–	–
Fixed price receiver, notional amounts, Dec. 31, 2007	**16,009**	**61,977**	**–**	**1,644**	**15**
Fixed price receiver, notional amounts, Dec. 31, 2006	21,536	26,231	–	–	–
Maximum term in months, Dec. 31, 2007	**24**	**12**	**76**	**23**	**2**
Maximum term in months, Dec. 31, 2006	33	16	24	–	–

B. Other Risk Management Assets and Liabilities

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

As at Dec. 31	**2007**			**2006**
Balance Sheet – Other	**Hedges**	**Non-hedges**	**Total**	**Total related to non-Energy Trading**
Risk management assets				
Current	**$ 56.9**	**$ 2.3**	**$ 59.2**	$ 11.2
Long-term	**126.1**	**–**	**126.1**	43.2
Risk management liabilities				
Current	**(16.0)**	**(2.6)**	**(18.6)**	(2.1)
Long-term	**1.2**	**(12.9)**	**(11.7)**	(13.0)
Net risk management assets (liabilities) outstanding	**$ 168.2**	**$ (13.2)**	**$ 155.0**	$ 39.3

The following table illustrates the impact of adopting new standards for financial instruments *(Note 1 (T))* and the movements in the fair value of the Corporation's other net risk management assets and liabilities during the year ended Dec. 31, 2007:

	Hedges [2]	Non-hedges [2]	Total
Net other risk management assets (liabilities) at Dec. 31, 2006 – *as reported*	$ 50.1	$ (10.8)	$ 39.3
Net other risk management assets (liabilities) at Jan. 1, 2007 – *fair value* [1]	58.0	(10.3)	47.7
Contracts realized, amortized or settled during the period	(39.5)	(1.3)	(40.8)
Changes in values attributable to market price and other market changes	112.0	(1.6)	110.4
New contracts entered into during the current period	37.7	–	37.7
Net other risk management assets (liabilities) outstanding at Dec. 31, 2007 – *fair value*	**$ 168.2**	**$ (13.2)**	**$ 155.0**

1 *As a result of adopting new accounting standards* (Note 1(T)).
2 *Based on market inputs, which are directly observable.*

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

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

	2008	2009	2010	2011	2012	2013 and thereafter	Total
Hedges	$ 41.0	$ 72.4	$ 24.0	$ 10.9	$ 4.1	$ 15.8	$ 168.2
Non-hedges	$ (0.4)	$ (12.8)	$ –	$ –	$ –	$ –	$ (13.2)
Total	$ 40.6	$ 59.6	$ 24.0	$ 10.9	$ 4.1	$ 15.8	$ 155.0

I. Hedges of Foreign Operations

Details of the notional amounts of cross-currency interest rate swaps are as follows:

As at Dec. 31	2007			2006		
	Amount	Fair value	Maturities	Amount	Fair value	Maturities
Australian dollars	**AUD$34.0**	**$ 1.2**	**2009**	AUD$34.0	$ (0.6)	2009
U.S. dollars	**U.S.$533.1**	**$ 105.7**	**2009–2014**	U.S.$528.2	$ 41.1	2007–2014

In addition, the Corporation has designated U.S. dollar denominated long-term debt *(Note 19)* in the amount of U.S.$600.0 million (2006 – U.S.$600.0 million) as a hedge of its net investment in U.S. dollar denominated companies with $265.8 million of related foreign currency losses (2006 – $173.6 million) included in OCI, with cumulative gain or loss reported in AOCI.

The Corporation has also hedged a portion of its net investment in self-sustaining subsidiaries with foreign currency forward sales contracts as shown below:

As at Dec. 31	2007			2006		
	Amount	Fair value	Maturities	Amount	Fair value	Maturities
U.S. dollars	**U.S.$472.7**	**$ 52.3**	**2008**	U.S.$472.5	$ 9.9	2007–2008
Australian dollars	**AUD$81.8**	**$ 1.1**	**2008**	AUD$48.8	$ (0.2)	2007

II. Hedges of Future Foreign Currency Obligations

The Corporation has hedged future foreign currency obligations through forward purchase contracts as follows:

As at Dec. 31	2007					2006			
Currency sold	Amount sold	Currency purchased	Amount purchased	Fair value asset (liability)	Maturities	Amount sold	Amount purchased	Fair value asset (liability)	Maturities
Canadian dollars	**$ 95.7**	**U.S.$**	**U.S.$86.6**	**$ (10.7)**	**2008–2010**	$ 32.9	U.S.$28.8	$ 0.3	2007
U.S. dollars	**–**	**CDN$**	**–**	**–**	**–**	$ 2.1	$2.3	–	2007
Australian dollars	**$ 6.0**	**CDN$**	**$5.2**	**$ 0.1**	**2008**	–	–	–	–
Australian dollars	**$ 2.0**	**U.S.$**	**$1.7**	**–**	**2008**	–	–	–	–
U.S. dollars	**$ 1.7**	**GBP**	**GBP0.9**	**–**	**2008**	–	–	–	–
Canadian dollars	**$ 69.1**	**Euro**	**EUR45.7**	**$ (3.3)**	**2008**	$ 36.9	EUR24.2	$ (0.2)	2007–2008

C. Credit Risk Management

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

The maximum credit exposure to any one customer for commodity trading and origination, excluding the California market receivables discussed in *Note 30* and including the fair value of open trading positions, is $6.3 million (2006 – $11.3 million).

9. Inventory

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

As at Dec. 31	2007	2006
Coal	$ 23.5	$ 44.9
Natural gas	6.6	8.1
Total	**$ 30.1**	$ 53.0

The change in inventory is outlined below:

Balance, Dec. 31, 2006	$ 53.0
Consumed	(19.6)
Change in foreign exchange rates	(3.3)
Balance, Dec. 31, 2007	**$ 30.1**

No inventory is pledged as security for liabilities.

For the year ended Dec. 31, 2007, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into income. During 2006, internally produced coal inventory at Centralia Thermal was written down to net realizable value. This writedown totaled $44.4 million *(Note 2)* and occurred as a result of the decision to cease activities at the Centralia coal mine. The Dec. 31, 2006 coal inventory balance reflects the value of inventory after this writedown.

10. Restricted Cash

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

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

The change in restricted cash is outlined below:

Balance, Dec. 31, 2006	$ 347.8
Change in foreign exchange rates	(48.6)
Amount returned to TransAlta	(56.8)
Balance, Dec. 31, 2007	**$ 242.4**

11. Investments

Investments mainly represent TransAlta's investment in the Corporation's wholly owned Mexican operations. As required under Accounting Guideline 15, *Consolidation of Variable Interest Entities*, of the CICA, TransAlta's Mexican operations are accounted for as equity subsidiaries. However, these plants are owned by TransAlta and managed as part of the Generation segment. The table below summarizes key information from these operations.

The change in investments is shown below:

Opening balance, Dec. 31, 2006	$ 154.5
Repayment of debt by Mexican operations	19.6
Equity loss	(49.5)
Closing balance, Dec. 31, 2007	**$ 124.6**

The table below summarizes total assets and liabilities for the Mexican operations:

As at Dec. 31	2007	2006
Total assets	$ 450.5	$ 526.9
Total liabilities	$ 368.7	$ 404.1

On Oct. 1, 2007 the Mexican government enacted law introducing a flat tax system 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. TransAlta has recorded a $28.2 million charge in equity loss above and a corresponding reduction in investments as a result of this change.

TransAlta has initiated a strategic review of the Mexican operations and has initiated a process to look for potential buyers for these assets. On Feb. 20, 2008, TransAlta announced the sale of the Mexican operations to InterGen Global Ventures B.V. ("InterGen") for U.S.$303.5 million *(Note 35)*.

12. Long-Term Receivables

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

During 2007, the Corporation prepared a revised decommissioning cost estimate of the future asset retirement costs *(Note 20)*. As a result, the total expected costs have been reduced by $18.7 million and the future recoveries have been reduced by $19.8 million and $6.8 million of the receivable expected to be received in the next 12 months has been reclassified to accounts receivable.

13. Property, Plant, and Equipment ("PP&E")

As at Dec. 31		2007			2006		
	Depreciation rates	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation	2%–50%	**$ 3,762.7**	**$ 1,452.6**	**$ 2,310.1**	$ 3,287.3	$ 1,300.6	$ 1,986.7
Thermal environmental equipment	2%–25%	**575.3**	**299.1**	**276.2**	611.5	288.5	323.0
Mining property and equipment	2%–50%	**617.3**	**330.0**	**287.3**	493.7	309.0	184.7
Gas generation	3%–50%	**2,156.8**	**944.3**	**1,212.5**	2,533.6	908.4	1,625.2
Geothermal generation	3%–33%	**288.4**	**41.5**	**246.9**	303.5	15.6	287.9
Hydro generation	1%–5%	**384.9**	**215.4**	**169.5**	375.2	210.9	164.3
Wind generation	3%–50%	**208.6**	**32.4**	**176.2**	207.8	25.2	182.6
Capital spares and other	2%–50%	**185.7**	**61.8**	**123.9**	206.2	55.9	150.3
Assets under construction	–	**181.2**	**–**	**181.2**	–	–	–
Coal rights [1]	–	**132.9**	**80.2**	**52.7**	132.7	76.0	56.7
Land	–	**51.8**	**–**	**51.8**	53.7	–	53.7
Transmission systems	3%–4%	**47.1**	**18.1**	**29.0**	43.7	16.9	26.8
Total		**$ 8,592.7**	**$ 3,475.4**	**$ 5,117.3**	$ 8,248.9	$ 3,207.0	$ 5,041.9

1 Coal rights are amortized on a unit of production basis, based on the estimated mine reserve.

The Corporation capitalized $6.0 million of interest to PP&E in 2007 (2006 – nil, 2005 – $3.4 million).

A decrease in foreign exchange rate from 2006 to 2007 has resulted in a $196.0 million decrease in net book value. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation loss is reflected in AOCI.

On Nov. 27, 2006, TransAlta ceased mining activities at the Centralia coal mine as a result of increased costs and unfavourable geological events. As a result of the associated mining and reclamation equipment including coal processing equipment and structures, haul roads, and other equipment were written down to the lower of net book value and net realizable value and are classified as assets held for sale *(Note 14)*.

In 2006, TransAlta sold excess turbines in inventory for net proceeds of $20.3 million which equaled their net book value.

During the first quarter of 2006, there was a change in the amortization period for the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan, and Meridian plants. Previously, these plants were being amortized using the unit-of-production method over the life of the plants. After reviewing the estimated useful life and considering the uncertainty for the plants' operations beyond the terms of the current sales contracts, TransAlta determined that it was more reasonable to allocate the remaining net book value of the plants on a straight-line basis over the remaining term of the respective contracts. For the year ended Dec. 31, 2006 the amortization related to the Ottawa, Mississauga, Windsor-Essex, Fort Saskatchewan, and Meridian plants is $13.4 million higher than the same period in 2005.

14. Assets Held for Sale

As a result of the decision to cease mining activities at the Centralia coal mine, all associated mining and reclamation equipment is being held for sale. All equipment has been recorded at the lower of net book value or anticipated realized proceeds. These assets are included in the Generation segment. During 2007, some of this equipment had been retained for reclamation activities, transferred to the Highvale mine for use in production of coal inventory, and allocated to potential future Westfields development and has been reclassified to property, plant, and equipment. The decision to retain equipment for use in reclamation activities at the Centralia coal mine and in operations at the Highvale mine was arrived at as the economics of retaining these assets was greater than the potential cash proceeds from disposing of these assets. The remainder of the change is due to the strengthening of the Canadian dollar relative to the U.S. dollar.

15. Goodwill

The change in goodwill is outlined below:

Balance, Dec. 31, 2006	$	137.5
Change in foreign exchange rates		(12.6)
Balance, Dec. 31, 2007	**$**	**124.9**

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

16. 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 CE Gen.

The majority of intangible assets are related to CE Gen and are therefore denominated in U.S. dollars. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect earnings and the cumulative translation loss is reflected in AOCI.

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2006	$ 473.0	$ 180.9	$ 292.1
Change in foreign exchange rates	(72.4)	(34.8)	(37.6)
Amortization	–	45.3	(45.3)
Balance, Dec. 31, 2007	**$ 400.6**	**$ 191.4**	**$ 209.2**

17. Other Assets

As at Dec. 31	2007	2006
Interest rate swaps *(Note 19)*	**$ 21.7**	$ 25.8
Deferred license fees	**22.3**	26.8
Deferred contract costs	**14.4**	16.1
Other	**24.2**	24.9
	$ 82.6	$ 93.6
Less current portion	**–**	(5.4)
Total other assets	**$ 82.6**	$ 88.2

Deferred license fees consist primarily of an Australian license which is being amortized on a straight-line basis over the useful life of the power station assets to which the license relates.

Deferred contract costs consist of prepayments related to long-term contracts, which are being amortized on a straight-line basis over the term of the related contracts.

18. Short-Term Debt

As at Dec. 31	2007		2006	
	Outstanding	Interest [1]	Outstanding	Interest [1]
Commercial paper	**$ 447.2**	**5.2%**	$ 199.3	4.3%
Bank debt [2]	**203.6**	**4.9%**	162.6	4.4%
Total short-term debt	**$ 650.8**		$ 361.9	

1 *Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.*
2 *Bank debt is in the form of Bankers' Acceptances.*

The short-term debt instruments are drawn on the $1.5 billion committed syndicated bank credit facility.

The $1.5 billion committed syndicated bank facility is dated July 2003 and is the primary source for short term liquidity. The facility is a five year revolver and was last renewed in May 2007, extending the maturity date to 2012. The syndicate is governed by reasonable commercial terms.

19. Long-Term Debt and Net Interest Expense

A. Amounts Outstanding

As at Dec. 31	2007			2006		
	Carrying value	Cost	Interest [1]	Carrying value	Cost	Interest [1]
Debentures, due 2008 to 2033	$ 956.9	$ 946.1	6.5%	$ 1,161.3	$ 1,146.4	6.1%
Senior Notes, U.S.$600.0 million	587.7	586.1	6.3%	683.6	693.2	6.3%
Non-recourse debt	241.6	241.6	7.4%	334.3	334.3	7.7%
Notes payable – Windsor plant	42.8	42.8	7.4%	46.9	46.9	7.4%
Commercial Loan Obligation	30.3	30.3	5.9%	–	–	–
Preferred securities	–	–	–	175.0	175.0	7.8%
	1,859.3	1,846.9		2,401.1	2,395.8	
Less: current portion	(153.8)	(153.8)		(424.7)	(424.7)	
Total long-term debt	$ 1,705.5	$ 1,693.1		$ 1,976.4	$ 1,971.1	

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

Fixed rate components of debentures and senior notes are hedged and therefore recorded at fair value. Non-recourse debt is not hedged and therefore recorded at cost.

Debentures bear interest at fixed rates ranging from 5.5 per cent to 7.3 per cent. A floating charge on the property and assets of TransAlta Utilities Corporation ("TAU"), a wholly owned subsidiary, has been provided as collateral for $265.0 million of the debentures as at Dec. 31, 2007. The interest rate on $200.0 million of the debentures amount has been converted to floating rates based on bankers' acceptance rates using receive fixed, pay floating interest rate swaps maturing in 2011 *(Note 8)*. Debentures of $100.0 million maturing in 2023 and $50.0 million maturing in 2033 are redeemable at the option of the holder in 2008 and 2009, respectively. Debentures in the amount of $200.0 million matured in 2007.

Senior notes U.S.$100.0 million of the U.S.$600.00 million has been converted to a floating rate based on LIBOR using receive fixed, pay floating interest rate swaps maturing in 2013. U.S.$300.0 million of the U.S.$600.0 million senior notes bear an interest rate of 5.75 per cent and mature in 2013. The remaining U.S.$300.0 million of the U.S.600.0 million senior notes bear an interest rate of 6.75 per cent and mature on July 15, 2012. All senior notes have been designated as a hedge of the Corporation's net investment in U.S. and Mexican operations *(Note 8)*.

Non-recourse debt consists of project financing debt, debt securities and senior secured bonds of CE Gen and debt related to the Wailuku acquisition. The CE Gen related assets have been pledged as security for the project financing debt which will mature in 2008, with a fixed interest rate of 8.56 per cent. The CE Gen debt securities are non-recourse, have maturity dates ranging from 2010 to 2018 and interest rates ranging from 7.48 per cent to 8.30 per cent. This debt is recorded at cost, the fair value as at Dec. 31, 2007, was $256.6 million (2006 – $345.3 million). The outstanding balance of the non-recourse senior secured bonds as of Dec. 31, 2007 was $133.0 million, bear interest at 7.42 per cent, and are due in 2018. The Wailuku debt at Dec. 31, 2007 is U.S.$9.0 million and bears interest at a floating rate of 3.75 per cent.

Notes payable – Windsor plant notes bear interest at fixed rates and are recourse to the Corporation through a standby letter of credit. These mature in 2008 to 2014.

Commercial loan obligation bears an interest rate of 5.89 per cent and will mature in 2023. This is an unsecured loan and requires annual payments of interest and principal.

Preferred securities In 2006, the Corporation provided irrevocable notice of redemption on Jan. 2, 2007 at a redemption price equal to 100 per cent of the principal amount of the preferred securities plus accrued and unpaid distributions thereon to the date of such redemption. Due to redemption, the supplemental diluted earnings per share are not calculated for 2007 (2006 – $0.22).

B. Principal Repayments

2008	$ 153.8
2009	237.6
2010	27.8
2011	250.5
2012	319.5
2013 and thereafter	857.7
Total [1]	$ 1,846.9

1 *Excludes impact of derivatives.*

C. Interest Expense

Year ended Dec. 31	2007	2006	2005
Interest on long-term debt	$ 144.7	$ 155.5	$ 169.3
Interest on short-term debt	26.3	12.7	14.9
Interest on preferred securities	–	13.6	16.5
Interest income	(31.7)	(13.3)	(8.7)
Capitalized interest	(6.0)	–	(3.4)
Net interest expense	$ 133.3	$ 168.5	$ 188.6

The Corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2007 relates to the Corporation's investment in Keephills 3 and Kent Hills (2005 – Genesee 3).

D. Interest Rate Risk Management

The Corporation has converted fixed interest rate debt with rates ranging from 5.75 per cent to 6.90 per cent to floating rates through receive fixed pay floating interest rate swaps *(Note 8)* as shown below:

As at Dec. 31	2007			2006		
	Notional amount	Fair value of swaps	Maturities	Notional amount	Fair value of swaps	Maturities
Fixed rate debt	$ 200.0	$ 10.9	2011	$ 200.0	$ 15.2	2011
	U.S.$100.0	$ 1.6	2013	U.S.$300.0	$ (9.7)	2013

The Corporation has a forward start pay fixed swap outstanding at fixed rates ranging from 4.04 per cent to 4.07 per cent, as shown below:

As at Dec. 31	2007			2006		
	Notional amount	Fair value of swaps	Maturity	Notional amount	Fair value of swaps	Maturity
Floating rate debt	U.S.$200.0	$ 9.3	2018	$ 125.0	$ 0.2	2017

Including the interest rate swaps above, 38.3 per cent of the Corporation's debt is subject to floating interest rates (2006 – 28.4 per cent).

At Dec. 31, 2007, a $12.5 million asset (2006 – nil) related to the fair value of the interest rate swaps was recorded in long-term risk management assets *(Note 8)*.

E. Guarantees

I. Letters of Credit *(also refer to Notes 20 and 33)*

Letters of credit are issued to counterparties that have credit exposure to certain subsidiaries. If the Corporation or its subsidiary does not pay amounts due under the contract, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Dec. 31, 2007 was $550.1 million (2006 – $633.1 million) with nil (2006 – nil) amounts exercised by third parties under these arrangements.

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

II. Other Credit Support Instruments

A subsidiary of the Corporation has entered into a credit derivative agreement. Under the terms of the agreement, upon any specified credit event by the Corporation or any named subsidiary, the counterparty would have the right to deliver senior debt of the Corporation or any named subsidiary in return for payment. The debt obligations referenced by this agreement have been included in the consolidated balance sheet and also include U.S.$243.0 million at Dec. 31, 2007 (2006 – U.S.$295.0 million) of loans made to subsidiaries of the Corporation *(Note 10)*. The carrying value as at Dec. 31, 2007 was nil (2006 – nil).

20. Asset Retirement Obligations

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

Balance, Dec. 31, 2005	$ 249.2
Liabilities incurred in period	7.6
Liabilities settled in period	(29.2)
Accretion expense	21.5
Revisions in estimated cash flows	79.1
Change in foreign exchange rates	0.3
Balance, Dec. 31, 2006	$ 328.5
Liabilities incurred in period	3.3
Liabilities settled in period	(38.4)
Accretion expense	23.6
Revisions in estimated cash flows	(18.7)
Change in foreign exchange rates	(22.1)
	$ 276.2
Less current portion	(42.8)
Balance, Dec. 31, 2007	**$ 233.4**

The Corporation has a right to recover a portion of future asset retirement costs. The estimated present value of these payments has been recorded as a long-term receivable *(Note 12)*.

During 2007, the Corporation prepared a revised decommissioning cost estimate of the future asset retirement costs at certain facilities. As a result, the total expected costs have been reduced by $18.7 million.

As a result of the decision to cease mining activities at the Centralia coal mine in 2006, reclamation activities were accelerated from the original end of mine life of 2032. This change in timing of cash flows increased the asset retirement obligation by $34.0 million. The remainder of the change in 2006 is from revised estimates at TransAlta's other facilities.

TransAlta estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $0.8 billion, which will be incurred between 2008 and 2072. The majority of the costs will be incurred between 2020 and 2030. A discount rate of eight per cent and an inflation rate of 2.4 per cent were used to calculate the carrying value of the asset retirement obligations. At Dec. 31, 2007, the Corporation had a surety bond in the amount of U.S.$192.0 million (2006 – U.S.$192.0 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2007, the Corporation had letters of credit in the amount of $49.7 million (2006 – $47.3 million) in support of future retirement obligations at the Alberta mines.

21. Deferred Credits and Other Long-Term Liabilities

As at Dec. 31	2007	2006
Deferred revenues and other	$ 28.0	$ 19.7
Power purchase arrangement in limited partnership	24.9	27.1
Accrued benefit liability *(Note 33)*	48.0	58.0
Centralia coal mine closure costs	–	25.6
Total deferred credits and other long term liabilities	**$ 100.9**	**$ 130.4**

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 TA Cogen.

Deferred revenue and other includes future revenues related to the sale of emission credits.

For the year ended Dec. 31, 2007, the Corporation paid $24.2 million of costs related to the closure of the Centralia coal mine. The difference between actual cash payments and the balance recorded as at Dec. 31, 2006 is due to the strengthening of the Canadian dollar relative to the U.S. dollar.

22. Non-Controlling Interests

A. Statements of Earnings

Year ended Dec. 31	2007	2006	2005
Stanley Power's interest in TA Cogen *(Note 34)*	$ 29.2	$ 35.3	$ 2.1
25 per cent interest in Saranac Partnership not owned by CE Gen	18.8	16.2	16.4
Total	**$ 48.0**	**$ 51.5**	**$ 18.5**

B. Balance Sheets

As at Dec. 31	2007	2006
Stanley Power's interest in TA Cogen	$ 467.0	$ 502.6
25 per cent interest in Saranac Partnership not owned by CE Gen	29.4	32.4
Total	**$ 496.4**	**$ 535.0**

23. 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	2007		2006		2005	
	Common shares (millions)	Amount	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	202.4	$ 1,782.4	198.7	$ 1,697.9	194.1	$ 1,611.9
Issued under dividend reinvestment and share purchase plan	–	–	3.0	70.0	3.5	68.1
Stock options expired	–	(2.2)	–	–	–	–
Issued on purchase of Vision Quest	–	–	–	–	–	0.2
Issued for cash under stock option plans	0.8	18.8	0.6	14.3	1.0	16.3
Issued under Performance Share Ownership Plan	0.1	2.8	0.1	0.1	0.1	1.2
Shares purchased under NCIB *(Note 24)*	(2.4)	(21.1)	–	–	–	–
Employee share purchase loans	–	0.1	–	0.1	–	0.2
Issued and outstanding, end of year	**200.9**	**$ 1,780.8**	**202.4**	**$ 1,782.4**	**198.7**	**$ 1,697.9**

The Corporation had 1.2 million outstanding employee stock options (2006 – 2.2 million, 2005 – 2.9 million). For the year ended Dec. 31, 2007, 0.8 million options with a weighted average exercise price of $20.84 were exercised resulting in 0.8 million shares issued, and 0.2 million options were cancelled with a weighted average exercise price of $17.52.

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 was last approved by shareholders 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 person. Each right will entitle the 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. Effective Jan. 1, 2007, the Corporation amended the DRASP plan whereby after, Dec. 31, 2006, the five per cent discount on the price of shares purchased through the DRASP plan and issued from treasury was suspended. After Dec. 31, 2006, 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 TSX on the investment dates.

D. Earnings Per Share ("EPS")

Year ended Dec. 31	2007	2006
Net earnings	**$ 308.8**	$ 44.9
Basic weighted average number of common shares outstanding	**202.5**	200.8
Impact of PSOP	**0.4**	0.4
Diluted weighted average number of common shares outstanding	**202.9**	201.2
Earnings per share		
Basic	**$ 1.53**	$ 0.22
Diluted	**$ 1.53**	$ 0.22

24. Shareholders' Equity

	Common shares	Retained earnings	Accumulated Other Comprehensive (Loss) Income	Total shareholders' equity
Balance, Dec. 31, 2006 *(Note 1)*	$ 1,782.4	$ 710.0	$ (64.5)	$ 2,427.9
Change in accounting policy *(Note 1)*	–	–	(177.3)	(177.3)
Balance, Dec. 31, 2006 – *as adjusted*	1,782.4	710.0	(241.8)	2,250.6
Net income for the year ended Dec. 31, 2007	–	308.8	–	308.8
Common shares issued (dividends declared)	19.5	(202.5)	–	(183.0)
Shares purchased under NCIB	(21.1)	(53.8)	–	(74.9)
Gains on translating financial statements of self-sustaining foreign operations	–	–	19.1	19.1
Losses on derivatives designated as cash flow hedges	–	–	(40.8)	(40.8)
Derivatives designated as cash flow hedges in prior periods transferred to the balance sheet and net earnings in the current period	–	–	18.7	18.7
Balance, Dec. 31, 2007	**$ 1,780.8**	**$ 762.5**	**$ (244.8)**	**$ 2,298.5**

Components of AOCI

Cumulative unrealized losses on translating financial statements of self-sustaining foreign operations, net of tax	$ (45.4)
Cumulative unrealized losses on cash flow hedges, net of tax	(199.4)
Accumulated Other Comprehensive Loss as at Dec. 31, 2007	**$ (244.8)**

Normal Course Issuer Bid ("NCIB") Program

On Sept. 11, 2007, TransAlta announced an expansion of its NCIB program. The Corporation may purchase, for cancellation, up to 20.2 million of its common shares or approximately 10 per cent of the 202.0 million common shares issued and outstanding as at April 23, 2007. The NCIB program started on May 3, 2007 and will continue until May 2, 2008. Purchases will be made on the open market through the TSX at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2007, TransAlta purchased 2,371,800 shares at an average price of $31.59 per share. The units were purchased for an amount higher than their weighted average book value per share ($8.92 per share) resulting in a reduction of retained earnings of $53.8 million.

Year ended Dec. 31	2007
Total shares purchased	2,371,800
Average purchase price per share	$ 31.59
Total cash paid	$ 74.9
Weighted average book value of shares cancelled	21.1
Reduction to retained earnings	$ 53.8

25. Capital

TransAlta's components of capital are listed below:

As at Dec. 31	2007	2006	Increase/ (decrease)
Short term debt including current portion of long-term debt	$ 804.6	$ 611.6	$ 193.0
Less: cash and cash equivalents	(50.9)	(65.6)	14.7
	753.7	546.0	207.7
Long-term debt			
Recourse	1,496.2	1,681.5	(185.3)
Non-recourse	209.3	289.6	(80.3)
Preferred securities	–	175.0	(175.0)
Non-controlling interests	496.4	535.0	(38.6)
Preferred shares	–	–	–
Common shareholders' equity			
Common shares	1,780.8	1,782.4	(1.6)
Retained earnings	762.5	710.0	52.5
Accumulated Other Comprehensive Loss	(244.8)	(64.5)	(180.3)
	4,500.4	5,109.0	(608.6)
Total Capital	$ 5,254.1	$ 5,655.0	$ (400.9)

The long-term portion of recourse debt was reduced from Dec. 31, 2006 as a result of scheduled payments. Preferred securities of $175 million were repaid on Jan. 2, 2007. Short-term debt has increased from Dec. 31, 2006 as a result of the timing of collection of revenue under Alberta PPAs.

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, therefore maintaining an investment grade credit rating is a priority. 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 Cash flow from operating activities divided by net interest expense per the consolidated statements of earnings. TransAlta estimates the target of this ratio to be a minimum multiple of four.

Cash flow to total debt Cash flow from operating activities per the consolidated statements of cash flow less changes in working capital divided by two year average of total debt. TransAlta estimates the target of this ratio to be minimum 25 per cent.

Debt to invested capital Short-term debt and long-term debt less cash divided by total debt, preferred securities, non-controlling interests, and common equity. TransAlta estimates the target of this ratio to be less than 55 per cent.

These ratios are presented below:

Year ended Dec. 31	2007	2006
Cash flow to interest (times)	6.6	5.5
Cash flow to total debt (%)	30.7	26.2
Debt to invested capital (%)	46.8	44.5

The increase in cash flow to interest resulted from increased cash from operating activities and lower interest expense. The increase in cash flow to total debt resulted from increased cash flow from operating activities and lower debt balances *(Notes 18 and 19).* Debt to invested capital increased as a result of adopting new accounting standards (*Note 1(T)*). TransAlta routinely monitors forecasts for earnings, capital expenditures, and scheduled repayment of debt to ensure that the above ratio targets can be met.

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	2007	2006	Increase/ (decrease)
Cash flow from operating activities	$ 847.2	$ 489.6	$ 357.6
Dividends paid	(204.8)	(133.9)	(70.9)
Capital asset expenditures	(599.1)	(223.7)	(375.4)
Net cash inflow	$ 43.3	$ 132.0	$ (88.7)

The decrease in the total above net cash flows resulted from higher capital expenditures on growth and higher dividends paid, partially offset by higher cash earnings. TransAlta will use these excess funds to invest in growth projects, reduce debt levels, and repurchase common shares.

TransAlta's strategy for managing capital remained unchanged from Dec. 31, 2006.

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 Corporations's indebtedness 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 cashflow coverage that would be considered typical of bank credit facilities of this nature.

26. Acquisitions and Disposals

A. Acquisitions

On Feb. 17, 2006, the Corporation acquired a 50 per cent ownership in Wailuku River Hydroelectric L.P. ("Wailuku") for U.S.$1.0 million (CDN$1.2 million). The acquisition is accounted for using the purchase method of accounting. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The financial operations of Wailuku have been proportionately consolidated with those of TransAlta.

Net assets acquired at assigned values:

Working capital, including cash of $0.3 million	$ (2.7)
Property, plant and equipment	26.2
Long-term debt, including current portion	(22.3)
Total	$ 1.2
Consideration:	
Cash	$ 1.2

B. Disposals

On Dec. 1, 2004, TransAlta completed the sale of its 50 per cent interest in the 220 megawatt ("MW") Meridian cogeneration facility located in Lloydminster, Saskatchewan to TA Cogen, owned 50.01 per cent by TransAlta for its fair value of $110.0 million.

27. Related Party Transactions

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

On March 8, 2006, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen at market prices during planned maintenance at the Sheerness plant in the second quarter of 2006. The swap was settled in the second quarter of 2006 and did not have a material effect on the financial statements. TA Cogen is 50.01 per cent owned by TransAlta and TEC is 100 per cent owned by TransAlta.

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

On March 8, 2005, TA Cogen entered into an agreement with TEC whereby TEC provided a financial fixed-for-floating price swap to TA Cogen during planned maintenance at Sheerness in the second quarter of 2005. This transaction did not have a material impact upon the financial statements of TransAlta.

28. Contingencies

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 greenhouse gas emissions ("GHG") intensity are set on a facility by facility basis. The legislation requires a 12 per cent reduction in carbon emission intensity from a baseline 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 TransAlta's Alberta-based coal facilities contain change-in-law provisions which allows TransAlta to recover most compliance costs from the PPA customers. After flow-through, the annual net compliance costs were $1.4 million for 2007. As at Dec. 31, 2007 $26.3 million was recorded in accounts payable and $24.9 million was recorded in accounts receivable related to GHG.

The Corporation has recorded the liability for compliance costs and applicable offsetting accounts receivable for expected revenue recoveries based on the upper limits defined under the applicable legislation. The actual obligation will be settled in 2008, at which time the actual amount may differ but is not anticipated to affect the net position of the Corporation.

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

29. Commitments

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 gas-fired capacity and all of its steam is committed to the customer under a long-term contract. The remaining capacity may be taken by the customer at specified rates 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.

Mexico's energy production is subject to 25-year contracts with the Comisión Federal de Electricidad. These contracts set availability targets and the price at which the plant will be paid per kilowatt of available capacity, as well as plant efficiency targets for recovery of fuel costs based on market prices.

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 megawatts, total megawatt hours and steam consumed, while TransAlta assumes the availability and heat rate risk. Effective Jan. 1, 2006, TransAlta signed a five-year agreement with the Ontario Power Authority to supply 400 MW of electricity to the Ontario electricity market. The remaining capacity is available for export to the merchant market, based on market prices. Production at the remaining Ontario plants is subject to contracts expiring in five to 10 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 these plants expire the same time as the energy production contracts and are with a different customer base. Ottawa has thermal contracts with three different customers. 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 power purchase agreement 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 will be in effect from Nov. 1, 2007 until Dec. 31, 2012.

At Centralia Thermal, a significant portion of production is subject to short- to medium-term energy sales contracts. In addition, a portion of the Corporation's energy sales from its gas plants are subject to medium- to long-term energy sales contracts.

Centralia Thermal has various coal supply and associated rail transport contracts to provide coal for the use in production. At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal. Both of these amounts are included under coal supply and mining agreements.

On June 21, 2007, TAU entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal to the Keephills 3 joint venture project. The total dragline purchase costs include approximately U.S.$104 million for the purchase of the equipment, and an additional $29 million for the assembly and commissioning of the dragline, for a total of approximately $150 million, with final payments for goods and services due by May 2010. Total payments under this agreement in 2007 were $18 million.

Keephills 3 plant construction costs via the Keephills 3 Limited Partnership are anticipated to be approximately $1.6 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $800 million.

On Jan. 19, 2007, TransAlta announced a 25-year contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 75 MW of wind power. TransAlta will construct, own, and operate a wind power facility in New Brunswick ("Kent Hills"). Commercial operations are expected to begin by the end of 2008. On July 17, 2007, TransAlta amended the power purchase agreement with New Brunswick Power to increase capacity under the agreement from 75 MW to 96 MW. Total capital costs for the Kent Hills wind power project will be approximately $170 million. TransAlta also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site. Under the purchase and sale agreement, TransAlta acquired Canadian Hydro's Fairfield Hill wind power site, including the option to develop the site at a future date, for $1.3 million. Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

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, operating leases, mining agreements, and interest on long-term debt are as follows:

	Fixed price gas purchase contracts	Operating leases	Coal supply and mining agreements	Interest on long-term debt [1]	Total
2008	$ 47.0	$ 10.8	$ 45.2	$ 120.9	$ 223.9
2009	26.3	9.5	49.3	112.5	197.6
2010	6.8	9.1	45.0	99.3	160.2
2011	6.8	8.9	44.8	88.1	148.6
2012	6.8	8.9	44.5	69.1	129.3
2013 and thereafter	40.9	67.3	355.1	502.4	965.7
Total	$ 134.6	$ 114.5	$ 583.9	$ 992.3	$ 1,825.3

1 *Includes impact of derivatives.*

30. Prior Period Regulatory Decision

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

TransAlta filed a cost of service based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006, TransAlta filed for rehearing of FERC's rejection. On Aug. 24, 2007, the U.S. Court of Appeals for the Ninth Circuit granted the appeal. TransAlta has requested rehearing, however, FERC has yet to make a ruling on such a request and such a decision is not expected in the near future.

During settlement negotiations, the complaintants have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (the "Summer Transactions"). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources ("CDWR") referred to as CERS (the "CERS Transactions"). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. 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.

31. Segment Disclosures

A. Description of Reportable Segments

The Corporation has two reportable segments: Generation and Commercial Operations & Development ("COD"). TransAlta's segments are supported by a corporate group that provides finance, treasury, legal, environmental health and safety, sustainable development, corporate communications, government relations, information technology, human resources, internal audit, and other administrative support.

Each business segment assumes responsibility for its operating results measured as operating income or loss.

The Generation segment owns coal, gas, wind, geothermal and hydro power plants in Canada, the United States, Mexico, and Australia, and generates its revenue from the sale of electricity, steam, gas and ancillary services. As required under Accounting Guideline 15, *Consolidation of Variable Interest Entities*, of the CICA, the Mexican operations are accounted for as equity subsidiaries *(Note 11)*. Generation expenses include COD's intersegment charge for energy marketing and financial risk management services in the amount of $27.3 million (2006 – $27.8 million; 2005 – $26.0 million).

The COD segment derives revenue and earnings 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. These results are included in the Generation segment. Operating expenses are net of the intersegment charges for provision of these energy marketing, financial risk management, commercial, portfolio and regulatory management services of $27.3 million (2006 – $27.8 million; 2005 – $26.0 million).

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. Segment revenues are net of intersegment transactions.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2007	Generation	COD	Corporate	Total
Revenues *(Note 1)*	$ 2,719.6	$ 55.1	$ –	$ 2,774.7
Fuel and purchased power *(Note 1)*	(1,230.7)	–	–	(1,230.7)
Gross margin	1,488.9	55.1	–	1,544.0
Operations, maintenance and administration	446.9	33.7	96.2	576.8
Depreciation and amortization *(Note 1)*	391.3	1.4	13.2	405.9
Taxes, other than income taxes	19.9	–	0.3	20.2
Intersegment cost allocation	27.3	(27.3)	–	–
Operating expenses	885.4	7.8	109.7	1,002.9
Operating income (loss)	$ 603.5	$ 47.3	$ (109.7)	$ 541.1
Foreign exchange gain				3.2
Gain on sale of equipment *(Note 14)*				15.7
Net interest expense *(Note 19)*				(133.3)
Equity loss *(Note 11)*				(49.5)
Earnings before non-controlling interests and income taxes				**$ 377.2**

Year ended Dec. 31, 2006 *(Restated, Note 1)*	Generation	COD	Corporate	Total
Revenues	$ 2,611.9	$ 65.7	$ –	$ 2,677.6
Fuel and purchased power *(Notes 1 and 2)*	(1,186.2)	–	–	(1,186.2)
Gross margin	1,425.7	65.7	–	1,491.4
Operations, maintenance and administration	458.3	36.9	86.1	581.3
Depreciation and amortization *(Note 1)*	396.9	1.3	12.1	410.3
Taxes, other than income taxes	21.1	–	0.2	21.3
Intersegment cost allocation	27.8	(27.8)	–	–
Operating expenses	904.1	10.4	98.4	1,012.9
Mine closure charges *(Note 2)*	191.9	–	–	191.9
Asset impairment charges *(Note 3)*	130.0	–	–	130.0
Operating income (loss)	$ 199.7	$ 55.3	$ (98.4)	$ 156.6
Foreign exchange loss				(0.5)
Net interest expense *(Note 19)*				(168.5)
Equity loss *(Note 11)*				(17.0)
Loss before non-controlling interests and income taxes				$ (29.4)

Year ended Dec. 31, 2005 *(Restated, Note 1)*	Generation	COD	Corporate	Total
Revenues *(Note 1)*	$ 2,607.5	$ 56.9	$ –	$ 2,664.4
Fuel and purchased power *(Note 1)*	(1,222.4)	–	–	(1,222.4)
Gross margin	1,385.1	56.9	–	1,442.0
Operations, maintenance and administration	481.1	38.5	76.4	596.0
Depreciation and amortization *(Note 1)*	354.9	1.7	11.3	367.9
Taxes, other than income taxes	21.3	–	–	21.3
Intersegment cost allocation	26.0	(26.0)	–	–
Operating expenses	883.3	14.2	87.7	985.2
Asset impairment charges *(Note 3)*	36.2	–	–	36.2
Operating income (loss)	$ 465.6	$ 42.7	$ (87.7)	$ 420.6
Foreign exchange gain				1.3
Net interest expense *(Note 19)*				(188.6)
Equity loss *(Note 11)*				(0.9)
Earnings before non-controlling interests and income taxes				$ 232.4

II. Selected Balance Sheet Information

Dec. 31, 2007	Generation	COD	Corporate	Total
Goodwill *(Note 15)*	**$ 95.4**	**$ 29.5**	**$ –**	**$ 124.9**
Total segment assets	**$ 5,949.6**	**$ 146.7**	**$ 1,082.4**	**$ 7,178.7**

Dec. 31, 2006				
Goodwill *(Note 15)*	$ 108.0	$ 29.5	$ –	$ 137.5
Total segment assets	$ 6,159.3	$ 185.0	$ 1,115.8	$ 7,460.1

III. Selected Cash Flow Information

Year ended Dec. 31, 2007	Generation	COD	Corporate	Total
Capital expenditures	**$ 577.8**	**$ 4.7**	**$ 16.6**	**$ 599.1**

Year ended Dec. 31, 2006				
Capital expenditures	$ 205.9	$ 1.6	$ 16.2	$ 223.7
Acquisitions	$ 1.2	$ –	$ –	$ 1.2

Year ended Dec. 31, 2005				
Capital expenditures	$ 313.6	$ 1.5	$ 10.8	$ 325.9

IV. Depreciation and Amortization Expense per Statements of Cash Flows

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

Year ended Dec. 31	2007	2006	2005
Depreciation and amortization expense for reportable segments	$ 405.9	$ 410.3	$ 367.9
Mining equipment depreciation, included in fuel and purchased power	32.8	49.0	52.3
Accretion expense, included in depreciation and amortization expense	(23.6)	(21.5)	(19.3)
Depreciation and amortization expense per statements of cash flows	**$ 415.1**	$ 437.8	$ 400.9

C. Geographic Information

I. Revenues

Year ended Dec. 31	2007	2006	2005
Canada	$ 1,742.0	$ 1,761.7	$ 1,699.0
U.S.	931.8	825.1	$ 869.2
Australia	100.9	90.8	96.2
Total revenue	**$ 2,774.7**	$ 2,677.6	$ 2,664.4

II. Property, Plant and Equipment and Goodwill

	Property, plant and equipment *(Note 13)*		Goodwill *(Note 15)*	
As at Dec. 31	2007	2006	2007	2006
Canada	$ 3,876.9	$ 3,694.2	$ 56.5	$ 56.5
U.S.	1,087.3	1,182.2	68.4	81.0
Australia	153.1	165.5	–	–
Total	**$ 5,117.3**	$ 5,041.9	$ 124.9	$ 137.5

32. Stock-Based Compensation Plans

At Dec. 31, 2007, the Corporation had three 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.

IV. Mexican Phantom Plan

The Mexican phantom plan mirrors the rules of the Australian plan, with the first grant occurring in 2005.

Summary of the total options outstanding and options exercisable at Dec. 31, 2007 are shown below:

	Options outstanding				Options exercisable		
	Number outstanding at Dec. 31, 2007 (millions)	Weighted average remaining contractual life (years)		Weighted average exercise price	Number exercisable at Dec. 31, 2007 (millions)		Weighted average exercise price
Range of exercise prices							
$10.67–$18.00	**0.7**	**6.2**	**$**	**16.21**	**0.3**	**$**	**15.26**
$18.01–$23.00	**0.2**	**4.0**		**20.83**	**0.2**		**20.83**
$23.01–$27.70	**0.2**	**3.3**		**27.70**	**0.2**		**27.70**
$10.67–$27.70	**1.1**	**5.3**	**$**	**19.28**	**0.7**	**$**	**20.51**

B. Performance Stock Option Plan

In 1999, the Corporation expanded enrolment in the stock option program to include all Canadian employees of the Corporation, excluding the level of director and above, by issuing stock options with an expiry date of 2009 and vesting dependent upon achieving certain earnings per share targets.

Year ended Dec. 31	2007			2006			2005		
	Number of share options (millions)		Weighted average exercise price	Number of share options (millions)		Weighted average exercise price	Number of share options (millions)		Weighted average exercise price
Outstanding, beginning of year	**0.2**	**$**	**22.73**	0.2	$	22.62	0.2	$	22.44
Exercised	**(0.1)**		**22.75**	–		21.99	–		21.33
Cancelled or expired	**–**		**–**	–		23.05	–		23.05
Outstanding, end of year	**0.1**	**$**	**22.71**	0.2	$	22.73	0.2	$	22.62

At Dec. 31, 2007, the Corporation had 3,500 options under this plan with an exercise price of $14.15 and a weighted average remaining contractual life of 2.0 years and 88,625 options with an exercise price of $23.05 and a weighted average remaining contractual life of 1.1 years outstanding. At Dec. 31, 2007, all outstanding options had vested.

C. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, which commenced in 1997, the Corporation was authorized to grant to employees and directors up to an aggregate of 2.0 million common shares. The number of common shares which could be issued under both the PSOP and the share option plans, however, could not exceed 6.0 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. 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 S&P/TSX Composite Index. Expense related to this plan is recorded during the period earned, with the corresponding payable recorded in liabilities.

On Dec. 31, 2001, the plan was modified so that after three years, once the PSOP eligibility has been determined, 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. In addition, the number of common shares the Corporation is authorized to grant under the terms of the PSOP was increased to 4.0 million common shares and the maximum number of common shares which may be issued under both the PSOP and share option plans was increased to 13.0 million common shares.

Year ended Dec. 31	2007	2006	2005
Number of awards outstanding, beginning of year (in millions)	**1.2**	1.1	1.5
Granted	**0.4**	0.6	0.4
Awarded	**(0.1)**	(0.1)	(0.1)
Cancelled or expired	**(0.5)**	(0.4)	(0.7)
Number of awards outstanding, end of year	**1.0**	1.2	1.1

In 2007, PSOP compensation expense was $7.2 million after-tax (2006 – $3.7 million after-tax, 2005 – $7.0 million after-tax), which is included in OM&A expense in the statements of earnings. In 2007, 103,896 common shares were issued at $33.35 per share. In 2006, 137,039 common shares were issued at $25.41 per share. In 2005, 65,332 common shares were issued at $25.41 per share.

D. 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 no longer 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, 2007, accounts receivable from employees under the plan totalled $0.3 million (2006 – $0.4 million).

E. Stock-Based Compensation

At Dec. 31, 2007, the Corporation had 1.2 million outstanding employee stock options (2006 – 2.2 million).

Employee stock options, outstanding at Dec. 31, 2006	2.2
Exercised	(0.8)
Cancelled	(0.2)
Employee stock options, outstanding at Dec. 31, 2007	**1.2**

The Corporation uses the fair value method of accounting for awards granted under its fixed stock option plans and its performance stock option plan. In March 2005, 1.2 million options were granted. One quarter of the options granted vest on each of the first, second, third and fourth anniversaries of the date of grant and expire after 10 years. The estimated fair value of these options granted was determined using the binomial model and the following assumptions, resulting in a fair value of $6.84 per option:

Risk free interest rate (%)	4.3
Life of the options (years)	10
Dividend rate (%)	5.6
Volatility in the price of the Corporation's shares (%)	47.0

The estimated fair value of these stock options granted in 2002 and prior was determined using the binomial model using the following assumptions, resulting in a weighted-average fair value of $4.25:

Risk free interest rate (%)	5.9
Expected hold period to exercise (years)	7.0
Volatility in the price of the Corporation's shares (%)	28.3

33. Employee Future Benefits

A. Description

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

The latest actuarial valuations of the registered and supplemental pension plans were as at Dec. 31, 2006. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2007. The effective date of the next required valuation for funding purposes is Dec. 31, 2008. 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 $ 48.2 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, 2007. The effective date of the next required valuation for funding purposes is Dec. 31, 2010.

B. Costs Recognized

Year ended Dec. 31, 2007	Registered	Supplemental	Other	Total
Current service cost	$ 3.7	$ 1.5	$ 1.4	$ 6.6
Interest cost	19.4	2.4	1.2	23.0
Actual return on plan assets	(10.4)	–	–	(10.4)
Actuarial (gains) losses in 2007	(14.8)	5.5	(1.5)	(10.8)
Difference between expected return and actual return on plan assets	(15.0)	–	–	(15.0)
Difference between amortized and actuarial (gain) loss on accrued benefit obligation for year	16.0	(3.9)	1.7	13.8
Difference between amortization of past service costs for the year and actual plan amendments for the year	0.1	(0.2)	0.3	0.2
Amortization of net transition obligation (asset)	(9.1)	0.3	–	(8.8)
Defined benefit (income) cost	(10.1)	5.6	3.1	(1.4)
Defined contribution option expense of registered pension plan	15.4	–	–	15.4
Net expense	$ 5.3	$ 5.6	$ 3.1	$ 14.0

Year ended Dec. 31, 2006	Registered	Supplemental	Other	Total
Current service cost	$ 4.4	$ 1.2	$ 1.5	$ 7.1
Interest cost	19.7	2.0	1.1	22.8
Actual return on plan assets	(35.4)	–	–	(35.4)
Actuarial (gains) losses in 2006	(0.5)	1.0	(0.2)	0.3
Difference between expected return and actual return on plan assets	10.2	–	–	10.2
Difference between amortized and actuarial loss on accrued benefit obligation for year	3.1	–	0.5	3.6
Difference between amortization of past service costs for the year and actual plan amendments for the year	0.1	(0.2)	0.3	0.2
Centralia coal mine closure charges	1.4	–	–	1.4
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.2)	4.3	3.2	1.3
Defined contribution option expense of registered pension plan	17.5	–	–	17.5
Net expense	$ 11.3	$ 4.3	$ 3.2	$ 18.8

Year ended Dec. 31, 2005	Registered	Supplemental	Other	Total
Current service cost	$ 4.2	$ 1.1	$ 1.3	$ 6.6
Interest cost	20.4	2.0	1.2	23.6
Actual return on plan assets	(43.9)	–	–	(43.9)
Actuarial losses in 2005	26.3	4.6	0.9	31.8
Past service cost in 2005	0.5	(1.2)	–	(0.7)
Difference between expected return and actual return on plan assets	19.8	–	–	19.8
Difference between amortized and actuarial gain on accrued benefit obligation for year	(23.9)	(4.3)	(0.6)	(28.8)
Difference between amortization of past service costs for the year and actual plan amendments for the year	(0.4)	1.2	0.3	1.1
Amortization of net transition obligation (asset)	(9.2)	0.3	–	(8.9)
Defined benefit (income) cost	(6.2)	3.7	3.1	0.6
Defined contribution option expense of registered pension plan	16.1	–	–	16.1
Net expense	$ 9.9	$ 3.7	$ 3.1	$ 16.7

In 2007, 2006 and 2005, the entire net expense is related to continuing operations.

C. Status of Plans

Year ended Dec. 31, 2007	Registered	Supplemental	Other
Fair value of plan assets	$ 356.2	$ 2.3	$ –
Accrued benefit obligation	372.5	48.7	23.0
Funded status plan deficit	(16.3)	(46.4)	(23.0)
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	0.6	(1.1)	3.0
Unamortized transition (asset) obligation	(27.6)	2.0	–
Unamortized net actuarial gains	40.7	14.6	4.2
Total recognized in financial statements:			
Accrued benefit liability	$ (2.6)	$ (30.9)	$ (15.8)
Amortization period in years (EARSL)	7	6	14

Year ended Dec. 31, 2006	Registered	Supplemental	Other
Fair value of plan assets	$ 374.3	$ 2.1	$ –
Accrued benefit obligation	398.6	43.6	23.5
Funded status plan deficit	(24.3)	(41.5)	(23.5)
Amounts not yet recognized in financial statements:			
Unrecognized past service costs	0.8	(1.4)	3.2
Unamortized transition (asset) obligation	(36.6)	2.3	–
Unamortized net actuarial gains	46.3	10.7	5.5
Total recognized in financial statements:			
Accrued benefit liability	$ (13.8)	$ (29.9)	$ (14.8)
Amortization period in years (EARSL)	7	7	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 deferred credits and other long-term liabilities.

Year ended Dec. 31, 2007	Registered	Supplemental	Other
Accrued current liabilities	$ 0.2	$ 0.1	$ 1.0
Other long-term liabilities	2.4	30.8	14.8
Accrued benefit liability	**$ 2.6**	**$ 30.9**	**$ 15.8**

Year ended Dec. 31, 2006	Registered	Supplemental	Other
Accrued current liabilities	$ –	$ 0.5	$ –
Other long-term liabilities	13.8	29.4	14.8
Accrued benefit liability	**$ 13.8**	**$ 29.9**	**$ 14.8**

D. Contributions

Expected cash flows are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2008 (expected)	$ 3.9	$ 2.6	$ 1.9	$ 8.4
Expected benefit payments				
2008	24.7	2.4	1.8	28.9
2009	25.2	2.5	1.9	29.6
2010	25.8	2.7	1.9	30.4
2011	26.5	2.8	2.0	31.3
2012	26.9	2.9	1.9	31.7
2013–2017	138.2	16.5	10.1	164.8

E. Plan Assets

	Registered	Supplemental	Other
Fair value of plan assets at Dec. 31, 2005	$ 369.4	$ 1.7	$ –
Contributions	(2.6)	0.5	1.2
Benefits paid	(27.6)	(0.1)	(1.2)
Effect of translation on U.S. plans	(0.4)	–	–
Actual return on plan assets [1]	35.5	–	–
Fair value of plan assets at Dec. 31, 2006	$ 374.3	$ 2.1	$ –
Contributions	1.5	4.5	2.3
Benefits paid	(28.9)	(4.3)	(2.3)
Effect of translation on U.S. plans	(1.1)	–	–
Actual return on plan assets [1]	10.4	–	–
Fair value of plan assets at Dec. 31, 2007	**$ 356.2**	**$ 2.3**	**$ –**

1 Net of expenses.

The Corporation's investment policy is to achieve 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 publicly traded common or preferred equity 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 target allocation percentages are 60 per cent equity and 40 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investment decisions 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 plan assets by major asset category at Dec. 31, 2007 and 2006 is as follows:

Year ended Dec. 31, 2007	Registered	Supplemental
Equity securities	**58.6%**	**–**
Debt securities	**40.8%**	**–**
Cash equivalents	**0.6%**	**100.0%**
Total	**100.0%**	**100.0%**

Year ended Dec. 31, 2006	Registered	Supplemental
Equity securities	62.3%	–
Debt securities	37.4%	–
Cash equivalents	0.3%	100.0%
Total	100.0%	100.0%

Plan assets include common shares of the Corporation having a fair value of $0.8 million at Dec. 31, 2007 (2006 – $1.1 million). The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2007 (2006 – $0.1 million).

F. Reconciliation of Accrued Benefit Obligations

	Registered	Supplemental	Other
Accrued benefit obligation as at Dec. 31, 2005	$ 402.7	$ 41.2	$ 23.4
Current service cost	4.3	1.2	1.5
Interest cost	19.7	2.1	1.2
Expected benefits paid	(25.9)	(1.8)	(1.2)
Effect of translation on U.S. plans	(0.7)	–	(0.2)
Actuarial (gain) loss	(1.5)	0.9	(1.2)
Accrued benefit obligation as at Dec. 31, 2006	$ 398.6	$ 43.6	$ 23.5
Current service cost	3.7	1.5	1.4
Interest cost	19.4	2.4	1.3
Expected benefits paid	(28.9)	(4.3)	(2.3)
Plan amendments	(0.1)	–	–
Effect of translation on U.S. plans	(1.6)	–	(0.4)
Actuarial (gain) loss	(18.6)	5.5	(0.5)
Accrued benefit obligation as at Dec. 31, 2007	**$ 372.5**	**$ 48.7**	**$ 23.0**

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations were as follows:

Year ended Dec. 31, 2007	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	**5.5**	**5.5**	**5.7**
Rate of compensation increase (%)	**3.7**	**3.8**	**–**
Benefit cost for year ended Dec. 31			
Discount rate (%)	**5.0**	**5.0**	**5.3**
Rate of compensation increase (%)	**3.8**	**3.8**	**–**
Expected rate of return on plan assets (%)	**7.1**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	**–**	**–**	**9.0–10.0**[1]
Dental care cost escalation (%)	**–**	**–**	**4.0**
Provincial health care premium escalation (%)	**–**	**–**	**2.5**

Year ended Dec. 31, 2006	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	5.1	5.0	5.3
Rate of compensation increase (%)	3.8	3.8	–
Benefit cost for year ended Dec. 31			
Discount rate (%)	5.0	5.0	5.2
Rate of compensation increase (%)	3.5	3.5	–
Expected rate of return on plan assets (%)	7.1	–	–
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	–	–	9.0–9.5[1]
Dental care cost escalation (%)	–	–	4.0
Provincial health care premium escalation (%)	–	–	2.5

1 Decreasing gradually to 5.0 per cent by 2015 for Canadian plans and by 2012 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. The estimated rate of return is lower than the historical returns of the appropriate indices.

34. Joint Ventures

Joint ventures at Dec. 31, 2007 included the following:

Joint venture	Ownership interest	Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by Canadian Utilities
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, and is operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, and is 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 EPCOR Utilities Inc.
Wailuku	50%	A run-of-river generation facility in Hawaii, operated by MidAmerican
Keephills 3	50%	Coal-fired plant under construction in Alberta. The plant is being developed jointly with EPCOR Utilities Inc.

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:

	2007	2006	2005
Results of operations			
Revenues	$ 609.0	$ 611.0	$ 619.9
Expenses	(454.3)	(457.2)	(481.1)
Non-controlling interests	(43.7)	(41.9)	(43.7)
Proportionate share of net earnings	$ 111.0	$ 111.9	$ 95.1
Cash flows			
Cash flow from operations	$ 111.7	$ 115.1	$ 111.5
Cash flow used in investing activities	(146.7)	(44.4)	(10.3)
Cash flow used in financing activities	(92.9)	(51.8)	(76.3)
Non-controlling interests			
Proportionate share of (decrease)/increase in cash and cash equivalents	$ (127.9)	$ 18.9	$ 24.9
Financial position			
Current assets	$ 91.1	$ 147.3	$ 162.5
Long-term assets	1,924.2	1,849.7	1,930.7
Current liabilities	(144.2)	(117.2)	(118.0)
Long-term liabilities	(389.8)	(503.2)	(552.7)
Non-controlling interests	(373.0)	(393.9)	(413.8)
Proportionate share of net assets	$ 1,108.3	$ 982.7	$ 1,008.7

35. Subsequent Events

Mexico Business

On Feb. 20, 2008, TransAlta announced the sale of the Mexican operations to InterGen for U.S.$303.5 million. The transaction is subject to regulatory approvals in Mexico and is expected to close by the end of the second quarter of 2008. TransAlta will record a charge to the first quarter earnings of approximately $55 – $65 million to reflect the difference between the book value and sale price of these assets.

Blue Trail

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

Dividend

On Jan. 31, 2008, TransAlta's Board of Directors approved an increase to the annual dividend to common shareholders to $1.08 from $1.00 per share. TransAlta's Board also declared a quarterly dividend of $0.27 per share on common shares payable April 1, 2008 to shareholders of record at the close of business March 1, 2008.

Greenhouse Gas Emissions

On Jan. 24, 2008 the Government of Alberta announced its intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing carbon capture and storage technologies, developing conservation and energy efficiency programs, and through increased investment in clean energy technologies. The first stage of this program is to create focus groups or task forces for each of these three areas and develop action plans. The Corporation is assessing the impact of this proposal upon TransAlta's operations and TransAlta's own investment in environmental technologies and programs. The PPAs for TransAlta's Alberta-based coal facilities contain change-in-law provisions that allow the Corporation to recover compliance costs from the PPA customers.

36. Comparative Figures

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

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2007	2006	2005	2004
Financial Summary				
EARNINGS STATEMENT				
Revenues	$ 2,774.7	$ 2,677.6	$ 2,664.4	$ 2,838.3
Operating income	$ 541.1	$ 156.6	$ 420.6	$ 478.1
Net earnings applicable to common shareholders	$ 308.8	$ 44.9	$ 198.8	$ 170.2
BALANCE SHEET				
Total assets	$ 7,178.7	$ 7,460.1	$ 7,740.7	$ 8,133.0
Short-term debt, net of cash and interest-earning investments	$ 599.9	$ 296.3	$ (66.2)	$ (102.7)
Long-term debt	$ 1,859.3	$ 2,220.8	$ 2,605.0	$ 3,057.9
Preferred shares of a subsidiary	$ –	$ –	$ –	$ –
Other non-controlling interests	$ 496.4	$ 535.0	$ 558.6	$ 616.4
Preferred securities	$ –	$ 175.0	$ 175.0	$ 175.0
Common shareholders' equity	$ 2,298.5	$ 2,427.9	$ 2,543.1	$ 2,472.7
Total invested capital	$ 5,254.1	$ 5,655.0	$ 5,756.3	$ 6,061.4
CASH FLOW				
Cash flow from operating activities	$ 847.2	$ 489.6	$ 619.4	$ 613.4
Cash flow used in investing activities	$ 410.1	$ 261.3	$ (242.1)	$ (65.4)
Common share information (per share)				
Net earnings	$ 1.53	$ 0.22	$ 1.01	$ 0.88
Dividends declared	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Book value (at year-end)	$ 11.39	$ 11.99	$ 12.80	$ 12.74
Market price:				
High	$ 34.00	$ 26.91	$ 26.66	$ 18.75
Low	$ 23.76	$ 20.22	$ 17.67	$ 15.25
Close (TSX at Dec. 31)	$ 33.35	$ 26.64	$ 25.41	$ 18.05
RATIOS (percentage except where noted)				
Debt/invested capital	46.8	44.5	43.9	47.4
Return on common shareholders' equity	13.1	1.8	7.0	6.5
Return on invested capital	9.8	2.4	7.1	7.5
Cash flow to total debt	30.7	26.2	23.0	18.5
Cash flow to interest coverage (times)	6.6	5.5	4.7	4.1
Dividend payout	65.6	447.7	113.0	120.0
Dividend yield	3.0	3.8	3.9	5.5
Price/earnings multiple	21.8	121.1	26.7	21.7
Weighted average common shares for the year (in millions)	202.5	200.8	196.8	192.7
Common shares outstanding at Dec. 31 (in millions)	200.9	202.4	198.7	194.1
Statistical Summary				
Number of employees	2,201	2,687	2,657	2,505
GENERATING CAPACITY (net MW) [3]				
Hydro	807	807	802	802
Coal	4,942	4,887	4,885	4,778
Gas	1,950	1,953	1,933	2,444
Renewables	315	315	315	313
Total generating capacity	8,024	7,962	7,935	8,337
Total generation production (GWh) [4]	50,395	48,213	51,810	54,560

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 restated to be presented on a gross basis.*
2. *Includes discontinued operations.*
3. *Represents TransAlta's ownership.*
4. *Includes discontinued operations.*

Ratio Formulas

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

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

2003	2002	2001	2000	1999	1998	1997
$ 2,508.6	$ 1,814.9 [1]	$ 2,559.5 [1]	$ 1,587.0	$ 1,029.4	$ 1,089.9	$ 1,656.4
$ 553.7	$ 223.9 [2]	$ 468.9 [2]	$ 604.6 [2]	$ 442.0 [2]	$ 660.1 [2]	$ 586.6
$ 234.2	$ 189.9	$ 214.6	$ 279.8	$ 170.1	$ 211.4	$ 182.6
$ 8,420.2	$ 7,419.6	$ 7,877.9	$ 7,627.1	$ 6,038.4	$ 5,392.6	$ 4,882.2
$ (35.2)	$ 146.7	$ 475.2	$ 220.5	$ (173.6)	$ (149.4)	$ (20.3)
$ 3,162.1	$ 2,706.6	$ 2,511.1	$ 2,201.4	$ 2,177.4	$ 1,903.6	$ 2,198.0
$ –	$ –	$ –	$ 121.6	$ 268.3	$ 268.4	$ 267.6
$ 477.9	$ 263.0	$ 281.0	$ 253.4	$ 377.4	$ 503.3	$ 162.9
$ 450.8	$ 451.7	$ 452.6	$ 292.0	$ 287.1	$ –	$ –
$ 2,460.6	$ 2,039.6	$ 1,989.7	$ 1,957.4	$ 1,835.6	$ 1,855.0	$ 1,594.3
$ 6,516.2	$ 5,607.6	$ 5,709.6	$ 5,046.3	$ 4,772.2	$ 4,380.9	$ 4,202.5
$ 756.5	$ 437.7	$ 715.6	$ 188.7	$ 422.0	$ 470.7	$ 666.4
$ (535.1)	$ (36.2)	$ (1,076.9)	$ (205.0)	$ (988.8)	$ (137.2)	$ (319.7)
$ 1.26	$ 1.12	$ 1.27	$ 1.66	$ 1.00	$ 1.31	$ 1.14
$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 0.99	$ 0.98
$ 12.90	$ 12.01	$ 11.82	$ 11.61	$ 10.85	$ 10.94	$ 9.96
$ 19.55	$ 23.95	$ 30.13	$ 22.55	$ 25.15	$ 25.40	$ 22.75
$ 15.36	$ 16.69	$ 19.15	$ 13.20	$ 12.25	$ 18.20	$ 15.10
$ 18.53	$ 17.11	$ 21.60	$ 22.00	$ 14.15	$ 22.60	$ 22.55
47.9	50.9	52.3	48.0	45.6	40.0	51.8
10.3	3.5	10.9	11.7	9.2	12.3	11.5
9.1	4.0	8.7	12.3	9.7	15.4	13.7
17.9	16.1	21.8	25.3	21.7	22.8	22.0
3.3	3.8	–	–	–	–	–
79.0	241.8	78.5	75.8	99.7	75.8	85.7
5.4	5.8	4.6	4.6	7.1	4.4	4.4
14.7	41.7	17.3	16.7	14.2	17.3	19.8
185.3	169.6	169.0	168.8	169.5	161.3	159.7
190.7	169.8	168.3	168.6	169.2	169.6	160.0
2,563	2,573	2,656	2,363	2,679	2,455	2,667
801	801	800	800	800	800	800
4,777	4,966	5,090	5,016	3,676	3,676	3,676
2,499	1,333	1,108	1,054	1,464	1,008	832
245	44	–	–	–	–	–
8,322	7,144	6,998	6,870	5,940	5,484	5,308
53,134	46,877	44,136	40,644	37,771	39,001	36,401

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

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

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

Dividend yield = common share dividends/current year's close price

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

Shareholder Information

Annual Meeting
The Annual meeting will be held at 5:00 p.m. MST on Tuesday, April 22, 2008 at The Westin Edmonton, 10135 100th Street, Edmonton, Alberta.

Transfer Agent
CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Station
Toronto, Ontario M5C 2W9

Phone
North America:
1.800.387.0825 toll-free
Toronto/outside North America:
416.643.5500

E-mail
inquiries@cibcmellon.com

Fax
416.643.5501

Website
www.cibcmellon.com

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

Phone
North America:
1.800.387.3598 toll-free
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	Ratio
May 8, 1980	Stock split	3:1
Feb. 1, 1988	Stock split [1]	2:1
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares [2]	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.

2 TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration
Dividends are paid quarterly as determined by the Board. In determining the dividend, the Board reviews the Company's financial performance and balances financial liquidity requirements, capital investment, and returning capital to shareholders. The Board continues to focus on building sustainable earnings and dividend growth.

Important Dividend Dates

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2007	March 1, 2007	Feb. 27, 2006	.25
July 1, 2007	June 1, 2007	May 30, 2006	.25
Oct. 1, 2007	Sept. 1, 2007	Aug. 30, 2006	.25
Jan. 1, 2008	Dec. 1, 2007	Nov. 29, 2006	.25
April 1, 2008	March 1, 2008	Feb. 27, 2007	.27

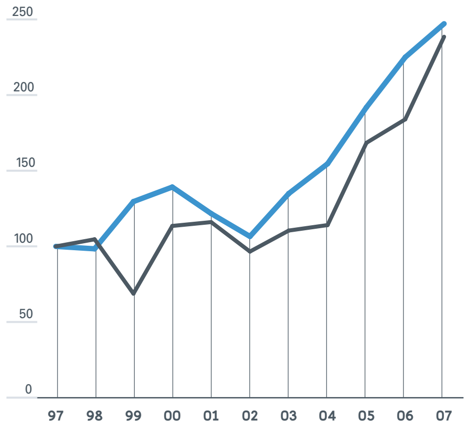
Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

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 auditing 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 Corporate Secretary of the Corporation.

Shareholder Highlights

Total Shareholder Return vs. S&P/TSX Composite Total Return Index

Years Ended Dec 31 ($)

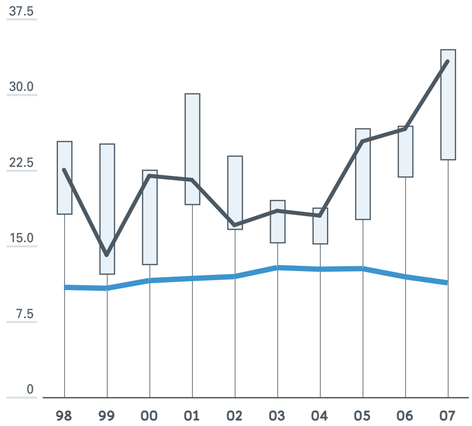


	97	98	99	00	01	02	03	04	05	06	07
TRANSALTA	100	105	69	114	116	97	110	114	168	184	**239**
S&P/TSX COMPOSITE INDEX	100	98	130	139	122	107	135	155	192	225	**247**

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 1997 would be worth today, assuming the reinvestment of all dividends.

Ten-Year Trading Range and Market Value vs. Book Value

($ per share)

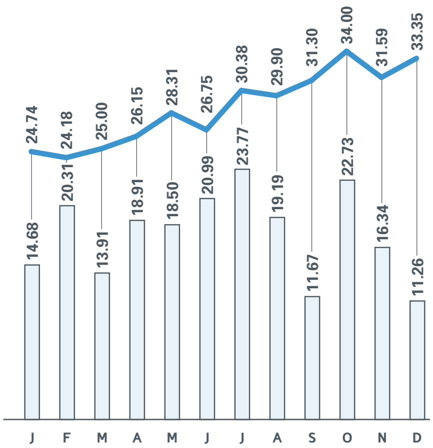


	98	99	00	01	02	03	04	05	06	07
MARKET VALUE	22.60	14.15	22.00	21.60	17.11	18.53	18.05	25.41	26.64	**33.35**
BOOK VALUE	10.94	10.85	11.61	11.82	12.01	12.90	12.74	12.80	11.99	**11.39**

TRADING RANGE

Monthly Volume and Market Price

(2007)

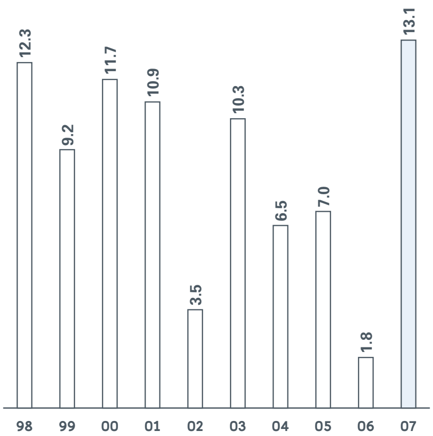


Volume (millions of shares)

TSX closing market price on last day of the month ($ per share)

Return on Common Shareholders' Equity

(%)



Corporate Information

TransAlta Corporate Officers

Stephen G. Snyder
President &
Chief Executive Officer

Brian Burden
Executive Vice-President
& Chief Financial Officer

William D.A. Bridge
Executive Vice-President,
Generation Technology &
Procurement & Material Management

Dawn Farrell
Executive Vice-President,
Commercial Operations & Development

Richard P. Langhammer
Executive Vice-President,
Generation Operations

Ken Stickland
Executive Vice-President,
Legal, Sustainable Development
& Environment, Health & Safety

Michael Williams
Executive Vice-President,
Human Resources, Information
Technology & Communications

Jeff A. Curran
Vice-President & Comptroller

Frank Hawkins
Vice-President & Treasurer

Maryse St.-Laurent
Corporate Secretary

TransAlta Senior Management

Mike Bartel
Vice-President, Engineering Services

Dawn de Lima
Vice-President, Corporate
Human Resources

Darcy Fedorchuk
Vice-President, Procurement
& Material Management

Stephen W. Foster
Vice-President, Generation
Human Resources

Derek Goodmanson
Vice-President, Major Maintenance

Kelly L. Gunsch
Vice-President, Commercial Operations

David J. Koch
Vice-President, Financial Operations

Mark B. Mackay
Vice-President, Energy Technology

Alex R. McFadden
Vice-President, Environment,
Health & Safety

Parviz Mohamed
Vice-President, Information Technology

Gregory P. Reinhart
Vice-President, Commercial Operations
& Development Human Resources

Martin Ridge
Vice-President, Internal Audit

Don Wharton
Vice-President, Sustainable Development

TransAlta Subsidiaries

Colin J. Mills
Country Manager, TransAlta Mexico
S.A. de C.V.

Doug Jackson
President, TransAlta Centralia
Generation LLC & 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 and others to call with respect to accounting irregularities and ethical violations. 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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Glossary

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.

Clean Coal Technology New technologies such as gasification using solid fuels (coal and coke) to produce power and chemical products with very low emissions.

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 Desulfurization Unit (Scrubber) Equipment used to remove sulfur 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 and hydrofluorocarbons.

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 hydroelectric 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 desulfurization 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.

TransAlta Corporation
Box 1900, Station "M", 110 – 12th Avenue SW, Calgary, Alberta, Canada T2P 2M1
Ph: 403.267.7110 www.transalta.com