TRANSALTA CORP
Form 6-K
March 28, 2003

FORM 6-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16
of the Securities Exchange Act of 1934

For the month of March, 2003

TRANSALTA CORPORATION

(Translation of registrant's name into English)

110-12th Avenue S.W., Box 1900, Station M , Calgary, Alberta, T2P 2M1

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F____ Form 40-F X__

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ..... No ..X...

If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-________

Evaluation of Disclosure Controls and Procedures

TransAlta has designed disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to the Chief Executive Officer and Chief Financial Officer by others within the Company, including its consolidated subsidiaries, on a regular basis, in particular during the period in which its Current Report on Form 6-K relating to financial results for the year ended December 31, 2002 are being prepared. The Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as of a date within 90 days of the date of this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded, as of that evaluation date, that the Company's disclosure controls and procedures were effective to ensure that material information relating to the Company, including its consolidated subsidiaries, was made known to them by others within those entities during the period in which this report was being prepared. There have been no significant changes in the internal controls or in other factors that could significantly affect internal controls subsequent to the date of the most recent evaluation by the Chief Executive Officer and Chief Financial Officer, including any corrective action with regard to significant deficiencies and material weaknesses.

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- **EXHIBITS**

Exhibit 1	2002 Management's Discussion and Analysis and consolidated financial statements for the period ended December 31, 2002.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This discussion and analysis should be read in conjunction with the consolidated financial statements and Auditors' Report included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). The effect of significant differences between Canadian and U.S. GAAP has been disclosed in Note 27 to the consolidated financial statements. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted.

FORWARD-LOOKING STATEMENTS

Management's discussion and analysis (MD&A) contains forward-looking statements, including statements regarding the business and anticipated financial performance of TransAlta Corporation (TransAlta or the corporation). In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. 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. Some of the risks, uncertainties, and factors include, but are not limited to: legislative and regulatory developments that could affect revenues, costs, the speed and degree of competition entering the market; global capital markets activity; timing and extent of changes in commodity prices, prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta operates; results of financing efforts; changes in counterparty risk; and the impact of accounting policies issued by Canadian and U.S. standard setters. Given these uncertainties, the reader should not place undue reliance on these forward-looking statements. See additional discussion under Risk Factors and Risk Management in this MD&A.

OVERVIEW

This review of TransAlta's 2002 financial results is organized by consolidated results and by business segment. TransAlta has two business segments: Generation and Energy Marketing. A third business segment, Independent Power Projects (IPP), was combined with the Generation segment effective Jan. 1, 2002 following changes to TransAlta's organizational structure. TransAlta's Transmission, Alberta Distribution and Retail (D&R), and New Zealand operations were sold on April 29, 2002, Aug. 31, 2000 and March 31, 2000, respectively. Prior period amounts have been reclassified to reflect these changes. Generation and Energy Marketing are supported by a corporate group that provides finance, treasury, legal, human resources and other administrative support. These corporate group overheads are allocated to the business segments if they are not directly attributable to discontinued operations.

Each business segment assumes responsibility for its operating results measured as earnings before interest, taxes and non-controlling interests (EBIT). EBIT should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with Canadian GAAP as an indicator of the corporation's performance or liquidity. TransAlta's EBIT is not necessarily comparable to a similarly titled measure of another company. EBIT has been calculated on a consistent basis for the three years ended Dec. 31, 2002 and is reconciled to net earnings applicable to common shareholders below:

Year ended Dec. 31	**2002**	2001	2000
EBIT	**$ 197.6**	$ 378.9	$ 408.9
Other income (expense)	**0.1**	1.5	(1.1)
Foreign exchange gain	**1.2**	0.8	0.1
Net interest expense	**(82.7)**	(88.1)	(91.4)
Earnings from continuing operations before income taxes and non-controlling interests	**116.2**	293.1	316.5
Income tax expense	**18.1**	89.9	128.5
Non-controlling interests	**20.1**	20.6	41.6

Earnings from continuing operations		**78.0**		182.6		146.4
Earnings from discontinued operations		**12.8**		45.1		89.1
Gain on disposal of discontinued operations		**120.0**		-		266.8
Extraordinary item		**-**		-		(209.7)
Net earnings		**210.8**		227.7		292.6
Preferred securities distribution, net of tax		**20.9**		13.1		12.8
Net earnings applicable to common shareholders	**$**	**189.9**	$	214.6	$	279.8

Some of the corporation's 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 for TransAlta include: revenue recognition; valuation and useful life of property, plant and equipment; valuation of goodwill; income taxes; and employee future benefits. See additional discussion under Critical Accounting Policies and Estimates in this MD&A.

TransAlta now measures capacity as net maximum capacity (see glossary for definition of this and other key terms) compared to nameplate capacity which had been previously used. The change was made to better reflect the actual capacities of assets and to be more consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated. Prior years have been adjusted to reflect the new method of measurement.

STRATEGY AND KEY PERFORMANCE INDICATORS

Strategy

The corporation's strategy is to maintain a strong balance sheet, run its existing assets efficiently and carefully manage the risk profile while methodically growing capacity. As discussed in the letter to shareholders, TransAlta has identified 11 goals to implement this strategy.

1.

Maintain investment grade credit ratings. TransAlta is focused on maintaining a strong balance sheet and investment grade credit ratings while maintaining the dividend. At Dec. 31, 2002, TransAlta's debt to invested capital ratio was 50.9 per cent, the corporation's credit rating was BBB+ and the 2002 annual dividend was $1.00 per common share.

2.

Steadily increase earnings per share. For the year ended Dec. 31, 2002, TransAlta earned $1.12 per common share compared to $1.27 in 2001. Earnings were lower due to lower market prices and increased maintenance costs. The gain on sale related to the Transmission business was offset by an arbitration decision related to the Wabamun power purchase arrangement (PPA), an impairment charge related to the Wabamun plant and turbine cancellation charges. TransAlta expects to achieve average earnings growth of five to 10 per cent per annum in the medium term. However, 2003 earnings will be impacted as a result of TransAlta accelerating maintenance at Alberta thermal plants in order to have assets operating at high availability rates in the future.

3.

Increase generation capacity. In 2002, TransAlta increased capacity by 200 megawatts (MW). In 2003, the Sarnia, Campeche and Chihuahua plants, as well as the McBride Lake joint venture project are forecast to be completed, increasing capacity by an additional 989 MW. In addition, the January 2003 acquisition of a 50 per cent interest in CE Generation LLC (CE Gen) increased capacity by an additional 378 MW. Due to this acquisition and the 50 per cent acquisition of Genesee 3, TransAlta reached 9,726 MW of owned capacity in operation, under construction or approved for development in January 2003. While TransAlta continues to explore strategic acquisitions to grow generating capacity, such growth will only be undertaken to the extent that it is affordable and supported by the balance sheet. As a result, the corporation expects that it will take longer than 2005 to increase capacity to 15,000 MW.

	2002	2001	2000
Owned Capacity in Operation (MW)	**7,144**	6,944	6,761

4.

Increase overall plant availability to 90 per cent. Availability is a key performance indicator for TransAlta. The corporation has approximately 90 per cent of its output under long-term contracts ; therefore , availability is critical to meeting these contracted quantities. Availability is also essential to producing electricity for sale at spot market prices. Overall plant availability for the year ended Dec. 31, 2002 was 88.4 per cent compared to 86.9 per cent in 2001.

	2002	2001	2000
Availability	**88.4**	86.9	87.8

5.

Reduce overhead and variable costs by $150 million. As of Dec. 31, 2002, the corporation identified $137.0 million in cost reductions related to coal extraction, variable operating costs and overhead costs compared to those incurred during 2001.

6.

Diversify by market and fuel type. To minimize risk, TransAlta's long-term goal is to ensure no more than 30 per cent of the corporation's generating capacity is in one fuel source or market. During 2002 TransAlta increased gas-fired capacity by a net 263 MW, renewable capacity by 44 MW, capacity in the U.S. by a net 126 MW and capacity in Australia by 34 MW. All of the 989 MW forecast to be completed in 2003 are fuelled by gas or renewables and 511 MW are outside of Canada. The 50 per cent acquisition of CE Gen in 2003 increased capacity from renewables by 163 MW and gas-fired assets by 215 MW, all within the U.S.

Owned and operated capacity by fuel source at Dec. 31, 2002 (MW)		
Coal	4,966	70%
Gas	1,333	19%
Hydro	801	11%
Renewable	44	1%

Owned and operated capacity by location at Dec. 31, 2002 (MW)		
Canada	5,165	72%
U.S.	1,699	24%
Australia	280	4%

7.

Minimum of 75 per cent of production under long-term contracts. Long-term contracts minimize TransAlta's exposure to market fluctuations. Maintaining a portion of production to be sold at market rates allows the corporation to capitalize on favourable market prices when available and reduces the risk of production shortfalls. In 2002, 90 per cent of the corporation's production was under long-term contracts. Of the new capacity scheduled for completion in

2003, the Mexican plants and McBride Lake joint venture are 100 per cent contracted and Sarnia is approximately 50 per cent contracted.

	2002	2001	2000
Contracted production (%)	**90**	92	96

8.

10 per cent of capacity from renewable energy sources by 2010. TransAlta is committed to reducing emissions while increasing production. A key factor in this strategy is increasing production from renewable energy sources. The acquisitions of Vision Quest Windelectric Inc. (Vision Quest) in December 2002 and a 50 per cent interest in CE Gen in January 2003 are part of TransAlta's commitment to sustainable development.

9.

Continue to capitalize on alliances. TransAlta has strategic alliances with EPCOR Utilities Inc. (EPCOR), ENMAX Corporation (ENMAX) and MidAmerican Energy Holdings Company (MidAmerican). The EPCOR alliance provided the opportunity to acquire a 50 per cent ownership in the 450 MW Genesee 3 project. The ENMAX partnership in the McBride Lake wind project provides the economic support to expand TransAlta's renewable energy business. MidAmerican owns the other 50 per cent interest in CE Gen.

10.

Use Energy Marketing to manage the corporation's asset risk. Energy Marketing acts to maximize margins from electricity, minimize the cost of natural gas used to generate electricity and reduce the risk to the corporation from unplanned outages by acquiring replacement power at the lowest possible price. During 2002, TransAlta sold uncontracted electricity at greater than market index prices and purchased electricity to meet contract obligations when it was more economic to buy rather than produce electricity.

11.

Reach zero net emissions from Canadian thermal plants by 2024. In 2002 TransAlta added additional gas and renewable capacity in Canada while reducing capacity at the coal-fired Wabamun facility. In addition, the purchase of offset credits and continued focus on technology will position the corporation to manage the future requirements of the Kyoto Protocol.

Key Performance Indicators

For the Generation segment, key performance indicators (KPIs) include availability, production, fuel and operating costs, and pricing applicable to non-contracted production. For the Energy Marketing segment, KPIs include trading volumes, margins and value at risk (VAR), which is a measure to manage earnings exposure from trading activities not related to TransAlta's assets. Each of these KPIs is discussed in greater detail in Segmented Business Results in this MD&A. KPIs for the corporate segment include the debt to invested capital ratio and credit ratings. These KPIs are discussed under Liquidity and Capital Resources.

MARKET TRENDS

Average Monthly Electricity Prices

	Mid-Columbia Price (US$/MWh)	Alberta System Market Price (Cdn$/MWh)
January 2000	$ 25.40	46.46
February 2000	26.25	47.07
March 2000	27.36	77.19
April 2000	23.38	93.68
May 2000	50.02	51.66
June 2000	131.26	106.73
July 2000	98.08	124.11
August 2000	166.06	202.09
September 2000	114.73	176.28
October 2000	96.71	253.28
November 2000	161.29	227.73
December 2000	524.65	188.91
January 2001	261.46	131.22
February 2001	275.22	116.75
March 2001	260.71	97.23
April 2001	289.74	114.82
May 2001	223.45	88.34
June 2001	62.00	63.59
July 2001	53.04	53.47
August 2001	39.71	52.37
September 2001	22.72	29.93
October 2001	24.49	43.94
November 2001	22.36	33.31

December 2001	24.24	33.61
January 2002	17.38	28.44
February 2002	19.45	22.37
March 2002	32.32	55.14
April 2002	19.44	45.04
May 2002	19.02	40.44
June 2002	7.51	46.23
July 2002	9.91	45.70
August 2002	17.90	32.03
September 2002	24.59	24.61
October 2002	24.49	44.33
November 2002	22.36	69.07
December 2002	24.24	70.88

Changes in the price of electricity can have a significant influence on TransAlta's financial performance. Fluctuating supply and demand resulted in high market volatility and high prices for electricity in late 2000 and early 2001. In the last half of 2001, additional capacity was brought to market and adverse economic conditions reduced demand; this combination resulted in lower volatility and prices throughout 2002, as shown in the chart above. Electricity price levels in Alberta and the Pacific Northwest are expected to be slightly higher in 2003 compared to 2002 due to higher natural gas prices and reduced hydro production as a result of lower snow pack.

Electricity prices generally increase as a result of higher natural gas prices. This benefits TransAlta's coal-fired facilities by increasing margins on merchant output. However, in the short term increased natural gas prices can also reduce spark spreads (the difference between the price of natural gas consumed to produce power and the selling price of electricity). As illustrated in the chart below, spark spreads were reduced in 2002 at TransAlta's merchant gas-fired facilities. The increases in electricity prices are not completely correlated to the increase in natural gas prices due to generation overcapacity in the market. The majority of the corporation's gas costs have been hedged or flow through to customers under the terms of agreements ; however , approximately 10 per cent of total production is subject to market prices for electricity and/or spark spread risk.

Average Monthly Spark Spreads[1] ($/MWh)

	Mid-Columbia Price vs. Sumas (US$)	Alberta System Market Price vs. AECO (Cdn$)
January 2000	9.56	25.58
February 2000	9.66	24.15
March 2000	9.23	51.17
April 2000	3.75	65.83
May 2000	27.61	19.59

June 2000	101.87	69.00
July 2000	73.89	90.61
August 2000	140.54	168.83
September 2000	81.55	129.99
October 2000	62.39	205.94
November 2000	87.50	174.84
December 2000	398.39	102.59
January 2001	202.81	51.99
February 2001	232.90	58.81
March 2001	220.96	42.99
April 2001	252.12	60.76
May 2001	195.12	46.63
June 2001	40.09	29.93
July 2001	37.03	28.64
August 2001	22.29	25.61
September 2001	11.00	11.53
October 2001	9.94	21.58
November 2001	7.42	10.49
December 2001	7.47	9.20
January 2002	4.43	6.44
February 2002	5.94	0.09
March 2002	13.99	24.66
April 2002	(0.93)	13.60
May 2002	0.18	10.72
June 2002	(6.67)	24.03
July 2002	0.68	11.23
August 2002	3.17	9.98
September 2002	5.23	16.25
October 2002	4.78	7.25
November 2002	5.64	30.74
December 2002	7.92	27.82

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

Since the bankruptcy of Enron and reduction of credit worthiness of other market participants, liquidity in the medium- and longer-term energy trading markets has decreased considerably. Activity levels in the short-term market have increased. Margins in the energy trading business have significantly declined relative to 2000 and 2001 as a result of lower prices and more efficient markets.

SUMMARY OF RESULTS

	2002	2001	2000
Availability (%)	**88.4**	86.9	87.8
Production (GWh)	**46,877**	44,136	40,644
Electricity trading volumes (GWh)	**103,076**	27,619	9,500
Gas trading volumes (million GJ)	**159.8**	99.3	135.7

	Amount	Per common share	Amount	Per common share	Amount	Per common share
Revenues [1]	**$1,723.9**		$2,319.4		$1,671.1	
Earnings from continuing operations [2]	**$ 57.1**	**$ 0.34**	$ 169.5	$ 1.00	$ 133.6	$ 0.79
Discontinued operations [3]	**12.8**	**0.07**	45.1	0.27	89.1	0.53
Earnings applicable to common shareholders	**$ 69.9**	**$ 0.41**	$ 214.6	$ 1.27	$ 222.7	$ 1.32
Gains on disposal of discontinued operations [3]	**120.0**	**0.71**	-	-	266.8	1.58
Extraordinary item [4]	**-**	**-**	-	-	(209.7)	(1.24)
Net earnings applicable to common shareholders	**$ 189.9**	**$ 1.12**	$ 214.6	$ 1.27	$ 279.8	$ 1.66
Cash flow from operating activities	**$ 437.7**		$ 715.6		$ 198.7	

1 From continuing operations. In accordance with changes to U.S. and Canadian GAAP, revenues from energy trading are now presented on a net basis. Prior periods have been reclassified to reflect this change.

2 Continuing operations include the Generation and Energy Marketing segments plus corporate costs not directly attributable to discontinued operations, and are net of preferred securities distributions.

3 Discontinued operations include the New Zealand operations, the Alberta D&R operation, the Edmonton Composter and the Transmission operation which were disposed of on March 31, 2000, Aug. 31, 2000, June 29, 2001 and April 29, 2002, respectively.

4 Extraordinary item arose from the recognition of previously unrecorded future income taxes and a write-down of property, plant and equipment related to Alberta Generation due to a change in accounting policy as a result of deregulation of the electric generation industry in Alberta commencing on Jan. 1, 2001.

In the third quarter of 2002, in response to changes in accounting standards in the U.S. with respect to energy trading activities, the corporation adopted a policy that all gains and losses on energy trading contracts not related to generation assets be shown as the net effect of sales less cost of purchased commodity in the statement of earnings.

Consistent with these recommendations, the corporation has chosen to disclose the gross transaction volumes for those energy trading contracts that are physically settled.

Revenues	**2002**	2001	2000
Generation	**$1,674.9**	$2,158.4	$1,593.3
Energy Marketing	**49.0**	161.0	77.8
	$1,723.9	$2,319.4	$1,671.1

Revenues decreased by $595.5 million in 2002 compared to 2001. The decrease is attributable to lower electricity market prices and lower margins on Energy Marketing activities, partially offset by improved availability and production. The $648.3 million increase in 2001 revenues compared to 2000 was primarily a result of high market prices in the first half of 2001, a full year of production from the Centralia plant and increased trading revenues in Energy Marketing.

Net earnings from continuing operations applicable to common shareholders decreased by $112.4 million in 2002 compared to 2001. The decrease was primarily due to lower revenues, the Wabamun plant impairment charge (described below), the cancellation of turbines ordered (described below), and the impact of the accelerated Alberta thermal plant maintenance schedule, partially offset by reduced purchased power requirements. The $35.9 million increase in 2001 over 2000 was primarily a result of increased earnings from Generation, gains on disposition from the sales of the Fort Nelson and the Fort Saskatchewan plants and increased returns from Energy Marketing activities. These increases were partially offset by the impact of unplanned outages at the Centralia plant.

Cash flow from operating activities was $277.9 million lower in 2002 compared to 2001. The decrease was due to lower earnings, the impact of the collection in 2001 of accounts receivable relating to the Alberta Power Pool upon implementation of deregulation on Jan. 1, 2001 ($170.0 million), the payment in 2002 to the Alberta Power Pool relating to the ancillary services revenue settlement ($49.9 million), described below, and the final installment of 2001 income taxes paid in the first quarter of 2002 ($109.0 million). In 2000, significantly increased working capital requirements resulted from deferred accounts receivable related to the sale of the discontinued Alberta D&R operation and increased trade receivables related to Centralia production and Energy Marketing activities.

SIGNIFICANT ONE-TIME ITEMS

These consolidated financial results include the following significant one-time items:

Purchase of Vision Quest

On Dec. 6, 2002 the corporation purchased the remaining interest in Vision Quest for cash of $21.3 million plus a previous loan of $19.8 million and $14.2 million in common shares. This transaction increased the corporation's total investment in the wind power company to $68.8 million. Included in the purchase price was $27.2 million of goodwill. Vision Quest owns and operates 67 wind turbine power plants with 44 MW of capacity and has a substantial resource base available for further expansion. Vision Quest and ENMAX each own a 50 per cent interest in the McBride Lake joint venture project with 75 MW under construction. Vision Quest's financial results for the period after acquisition ($0.6 million EBIT) are included in corporate results for segmented reporting purposes.

Decommissioning of Wabamun plant

After a detailed unit-by-unit engineering assessment, a review of environmental issues and a review of short- and long-term market forecasts, the corporation decided to implement a phased decommissioning of its four-unit 537 MW coal-fired Wabamun facility. The PPA for the plant expires at the end of 2003. The 139 MW unit three was removed from service on Nov. 29, 2002 after an unplanned outage, as it was not considered economical to return the unit to service. The corporation plans to retire units one and two (62 MW and 57 MW respectively) in 2004 and unit four (279 MW) in 2010 when its operating licence expires. As a result of this decision, the corporation recognized a pre-tax impairment charge of $110.0 million in the fourth quarter of 2002.

Turbine order cancellation

After examining expected market conditions and potential greenfield development opportunities against the corporation's risk profile, the corporation concluded that it could not use all its pre-purchased natural gas turbines. The corporation therefore cancelled orders for four turbines and as a result has recorded a pre-tax cancellation charge of $42.5 million for contract termination costs in 2002. The costs consisted solely of progress payments made to date. The remaining five turbines will be used in development projects.

Refinancing of foreign operations

During the third quarter of 2002, TransAlta restructured the financing of certain of its foreign operations. As a result, the corporation was able to record the benefit of previously unrecognized foreign tax loss carryforward balances. This restructuring contributed $11.2 million to net earnings in 2002.

Ancillary services revenue settlement

In July 2002, a dispute with the Balancing Pool of Alberta in respect of the allocation of hydro ancillary services deferred revenue under the PPAs was resolved. TransAlta repaid $49.9 million received in advance from the Balancing Pool. The settlement had no earnings impact as the corporation had not previously recognized the amount as revenue.

Wabamun arbitration decision

On May 23, 2002, the corporation received the arbitrators' decision with respect to the 10-month outage at Wabamun unit four, which resulted from fatigue cracks within the waterwall tubing of its boiler. The arbitrators confirmed that the outage qualified as a force majeure event, but also ruled that the corporation should have returned the unit to service more quickly. As a result of this decision, the corporation was required to pay $38.9 million plus interest of $2.7 million, all pre-tax. The payment was recorded as a reduction to revenue.

Gains on disposal of discontinued operations

On April 29, 2002, TransAlta's Transmission operation was sold for proceeds of $820.7 million, of which $818.0 million has been collected. The proceeds excluded $31.7 million in accounts receivable, which were retained and subsequently collected, and $4.4 million in accounts payable. The disposal resulted in a gain on sale of $120.0 million ($0.71 per common share), net of income taxes of $36.2 million.

Effective Dec. 31, 2000, the corporation adopted a plan to divest its composter facility in Edmonton, Alberta, Canada, which commenced commercial operations in August 2000. In the fourth quarter of 2000, the corporation recorded a write-down on the carrying value of the assets of $17.9 million , net of income tax recoveries of $13.8 million. On June 29, 2001, the facility was sold for cash proceeds of $97.0 million. No gain or loss resulted from the disposal.

On Aug. 31, 2000, TransAlta completed the disposition of its Alberta D&R operation for proceeds of $857.3 million and recorded an after-tax gain of $262.4 million ($1.55 per common share). In 2002, the outstanding amount due from Aquila Networks Canada (formerly UtiliCorp Networks Canada) relating to the sale of the D&R operation was collected in full.

On March 31, 2000, TransAlta completed the disposition of its investment in TransAlta New Zealand Limited for total proceeds of NZ$832.5 million (approximately Cdn$605 million) and recorded an after-tax gain of $22.3 million ($0.13 per common share).

Prior period regulatory decisions

Financial results for 2000, 2001 and 2002 were affected by Alberta Energy and Utilities Board (EUB) decisions related to other reporting periods. The impact of such regulatory decisions is recorded when the effect of such decisions is known, without adjustment to the financial statements of prior periods.

On April 16, 2002, the EUB rendered a negative decision of $3.3 million (pre-tax) with respect to TransAlta's hydro bidding strategy in 2000.

In December 2001, the EUB ruled that the Wabamun unit four outage qualified for relief under the Temporary Suspension Regulation (TSR) and ordered that TransAlta receive $11.0 million (pre-tax) to compensate the corporation for obligation payments incurred in 2000 as a result of the outage.

In September 2000, TransAlta received a negotiated settlement of $17.8 million (pre-tax) under the TSR to compensate the corporation for obligation payments incurred as a result of Alberta Generation production outages which occurred in 1999 and 2000. Approximately $13.5 million related to outages in 1999 and $4.3 million related to outages in 2000.

In February 2000, the EUB announced an amendment to its Phase I decision concerning a 1999 revenue requirement issue. The amendment resulted in TransAlta recognizing $30.6 million of pre-tax earnings.

Pierce Power

In September 2001, TransAlta reassessed its investment in the 154 MW Pierce Power plant as a result of weak economic conditions. Revenue hedges that were no longer expected to be effective were unwound and realized, resulting in the recognition of $121.8 million in revenue, partially offset by a write-down in the carrying amount of property, plant and equipment of $66.5 million and $52.3 million recognized in anticipated future plant operating costs. The plant remained available for production until it was decommissioned in September 2002. At Dec. 31, 2002, all accrued amounts had been realized.

Extraordinary item

On Dec. 31, 2000, TransAlta discontinued regulatory accounting and commenced the application of Canadian GAAP for non-regulated businesses for its Alberta Generation operations, following final confirmation of deregulation of the electricity generation industry in Alberta beginning on Jan. 1, 2001. As a result of the discontinuance of regulatory accounting, the corporation recorded an extraordinary non-cash after-tax charge of $209.7 million ($1.24 per common share). Of this amount, $189.9 million resulted from the recognition of future income tax liabilities that the corporation was previously exempted from recording.

NEW ACCOUNTING STANDARDS

On Jan. 1, 2002, the corporation retroactively adopted the new Canadian Institute of Chartered Accountants (CICA) standard for stock-based compensation. The new standard requires that stock-based payments to non-employees, direct awards of stock and awards that call for settlement in cash or other assets be accounted for using the fair value method of accounting. The fair value method is encouraged for other stock-based compensation plans, but other methods of accounting, such as the intrinsic value method, are permitted. Under the fair value method, compensation expense is measured at the grant date and recognized over the service period. Under the intrinsic value method, compensation expense is determined as the difference between the market price of the underlying stock and the exercise price of the equity instrument granted. If the intrinsic value method is used, disclosure is made of earnings and per share amounts as if the fair value method had been used. The corporation has elected to use the intrinsic value method of accounting for its fixed stock option plans and its performance stock option plan. Accordingly, no compensation cost has been recognized for these plans. Had the fair value method been used, the impact would be as disclosed in Note 16. Effective Jan. 1, 2003, TransAlta has elected to account for stock-based compensation in accordance with the fair value method and will expense stock-based compensation in respect of stock options granted after that date.

Effective Jan. 1, 2002, the corporation prospectively adopted the new CICA standard for goodwill and other intangibles. The new standards require business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. It also specifies that goodwill and certain intangibles are no longer subject to amortization, but are instead tested for impairment at least annually. The adoption of this standard resulted in the reclassification of $29.3 million from acquired intangibles to goodwill, which is no longer subject to amortization under the new standard. There was no impairment of goodwill upon adoption of this standard, nor was there an impairment at Dec. 31, 2002.

The CICA amended its standard on foreign currency translation effective Jan. 1, 2002. The changes require that translation gains and losses arising on long-term foreign currency denominated monetary items be included in income in the current period. Previously, these gains and losses were to be amortized over the life of the related item. As TransAlta designates long-term foreign currency denominated items as hedges of net investments in foreign operations, all gains and losses arising on the translation of these items are deferred and included in the cumulative translation adjustment account in shareholders' equity ; therefore , this amendment has no impact on TransAlta.

In November 2001, the CICA released an accounting guideline on hedging relationships, which specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges. The guideline also identifies situations where hedge accounting is to be discontinued. The guideline is effective for years beginning on or after July 1, 2003. TransAlta has adopted the guideline effective Jan. 1, 2002 and met the criteria for all hedging relationships with the exception of written swaptions, which are ineffective under the guideline. Hedge accounting was discontinued for the written swaptions in accordance with the guideline. The impact on earnings for the year ended Dec. 31, 2002 was a decrease of $2.0 million after tax.

The CICA has amended its standard on the recognition, measurement and disclosure of the impairment of long-lived assets. This standard is effective April 1, 2003 and requires that an impairment loss be recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected from its use and eventual disposition. The impairment loss is measured as the amount that the long-lived asset's carrying value exceeds its fair value. TransAlta early adopted this standard in the fourth quarter of 2002. In accordance with the standard, the impairment calculation for the Wabamun plant resulted in the recognition of an impairment charge of $110.0 million pre-tax, which is included in asset impairment and equipment cancellation charges.

In the third quarter of 2002, in response to changes in accounting standards in the U.S. with respect to energy trading activities, the corporation adopted a policy that all gains and losses on energy trading contracts not related to generation assets be shown net in the statement of earnings. Consistent with these recommendations, the corporation has chosen to disclose the gross transaction volumes for those energy trading contracts that are physically settled.

OUTLOOK

To achieve earnings growth, the corporation's focus will be to increase the efficiency and availability of generating assets, continue to improve productivity in operating, maintenance and administrative (OM&A) costs and add generating capacity. Energy Marketing will focus on maximizing pricing opportunities for non-contracted production from Generation and taking advantage of short-term market opportunities within pre-established risk limits.

Generation

The key factors affecting Generation's financial results for 2003 continue to be the megawatt capacity in production, the availability of and production from facilities, the pricing applicable to non-contracted production and the costs of production.

Grow capacity

Generating capacity in 2003 will be higher than in 2002 due to completion of the 252 MW Campeche plant, the 259 MW Chihuahua plant and the 75 MW McBride Lake joint venture which are scheduled to commence commercial operations in the first, third and fourth quarters of 2003, respectively. In connection with the construction of the Sarnia Regional Cogeneration Plant, TransAlta purchased 190 MW of existing operational assets during 2002 and subsequently decommissioned 55 MW. Construction of an additional 440 MW at Sarnia is expected to be completed in the first quarter of 2003 to provide 575 MW of ongoing generating capacity. The purchase of a 50 per cent interest in CE Gen in January 2003 will add another 378 MW of capacity. Availability for 2003 is expected to be similar to 2002 ; however , production is expected to be higher than in 2002 due to the increased capacity. Additional maintenance in Alberta will be offset by increased availability at Centralia.

At Dec. 31, 2002, assets under construction totalled $1,206.8 million and was comprised of the Sarnia, Campeche and Chihuahua plants. When these plants are commissioned, depreciation expense will be charged to operations.

Depreciation on the above plants as well as the Big Hanaford plant is expected to be approximately $58 million in 2003.

Power prices

Electricity spot prices in 2003 are expected to be slightly higher than in 2002 for the Alberta and Pacific Northwest markets due to higher natural gas prices and reduced hydro production as a result of lower snow pack. However, spark spreads are expected to compress due to excess generation capacity and the proportionately higher increase in the cost of natural gas as a result of high gas field decline rates, stagnant drilling activity and an increasing storage deficit. Expected electricity demand compared to levels of supply is expected to prevent prices from materially increasing over the medium term.

Legislation was passed in Ontario in late 2002 capping retail market prices at $43 per megawatt hour (MWh). Wholesale market prices have not been directly impacted by this decision, however liquidity in the Ontario market has declined. As a result, future revenues for merchant capacity at the Sarnia plant may be affected.

Exposure to volatility in electricity prices is substantially mitigated through long-term electricity sales contracts at fixed prices. Exposure to volatility in gas prices is substantially mitigated by the flow-through of the costs of natural gas to customers in some of these contracts and the existence of price caps in certain natural gas supply contracts. For 2003, approximately 85 per cent of output is contracted, a significant portion of which relates to the Alberta PPAs which are capacity related based on achieving agreed availability rates. The corporation will continue to focus on maximizing availability under these contracts.

Improving efficiency

Generation is continuing its focus on reducing coal costs and ongoing OM&A expenses. Areas for reductions were identified and have been, and continue to be, implemented. The benefits of these initiatives were partially realized in 2002, and are expected to become fully apparent in 2003 and beyond. There will be more planned maintenance expenses incurred at the Alberta thermal plants in 2003 than in 2002.

Energy Marketing

Short-term and real-time markets are expected to continue to be active. Energy Marketing will continue to concentrate on buying and selling electricity and gas in these markets. The electricity trades involve matching buyers and sellers, arranging for transmission capacity and scheduling movement of the commodity. This type of trading does not involve long-term contracts and therefore VAR and volatility related to fair value accounting is low.

In 2003, Energy Marketing is expected to achieve comparable results to 2002 based on similar levels of activity.

Capital expenditures and acquisitions

In 2003, capital expenditures will be approximately $830 million, of which approximately $275 million will be spent on the Genesee 3 project, described below, approximately $170 million will be spent to complete the two Mexican plants, $60 million will be spent on other growth projects and approximately $325 million will be spent on maintenance and productivity expenditures as a result of planned outages and preventative maintenance. Financing for these expenditures is expected to come from a combination of cash flow from operations, monetization of selected assets, the issuance of common shares and the issuance of debt. For further information on financing, see discussion under Liquidity and Capital Resources in this MD&A.

On Jan. 13, 2003, TransAlta and EPCOR announced an agreement for TransAlta to acquire a 50 per cent interest in EPCOR's Genesee 3 project for $395.0 million. On the same date, TransAlta paid EPCOR $157.0 million for TransAlta's share of project costs incurred to date. The 450 MW addition to the existing Genesee Generating Station is currently under construction southwest of Edmonton, Alberta. The two corporations will own and share costs for Genesee 3 equally. EPCOR will continue to manage the project's construction and will operate the plant upon commercial operation in early 2005. Both parties will independently dispatch and market their share of the electrical output from the unit through the Alberta Power Pool. Included in the arrangement is an option for EPCOR to purchase a 50 per cent interest in TransAlta's Centennial 1 project, described below. The option expires Dec. 31, 2005. EPCOR also has the option to purchase a 50 per cent interest in TransAlta's Sarnia plant, which may be exercised between January 2003 and March 2004.

In addition, on Jan. 24, 2003, the corporation announced the acquisition of a 50 per cent interest in CE Gen for US$205.0 million (approximately Cdn$312 million) plus approximately US$35.0 million of working capital (approximately Cdn$53 million) and non-recourse debt of approximately US$500.0 million (approximately Cdn$762 million). CE Gen, through its subsidiaries, is primarily engaged in the development, ownership and operation of independent power production facilities in the U.S. using geothermal resources and natural gas as fuel. CE Gen has 13 facilities with an aggregate operating capacity of 756 MW. The transaction closed on Jan. 29, 2003.

In February 2002, the EUB approved the previously announced Centennial project, which is a 900 MW merchant expansion at the Keephills site. The first phase one of the project (Centennial 1) is now part of the arrangement with EPCOR and the two corporations will jointly proceed with the development phase of the project. The decision to construct Centennial 1 will be made by TransAlta.

Equity Issuance

On March 14, 2003, the corporation filed a short-form prospectus for the issuance of 12.0 million common shares for gross proceeds of $192.0 million. The underwriters also exercised an option for an additional 3.0 million common shares for gross proceeds of $48.0 million. The offering includes a second option for the underwriters to purchase a further 2.25 million common shares for $36.0 million, exercisable until April 18, 2003. The transaction is expected to close on March 21, 2003.

Environmental

On Dec. 16, 2002, the Canadian government ratified the Kyoto Protocol. The Kyoto Protocol is not expected to have an impact on TransAlta's U.S., Mexican or Australian operations. TransAlta is not able to estimate the full impact the Protocol will have on its Canadian operations, as the Canadian government has not yet established an implementation plan. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change of Law' provisions that provide an opportunity to recover compliance costs from the PPA customers. As a member of the Canadian Clean Power Coalition, TransAlta, along with its peers, is exploring other means to reduce greenhouse gas emissions, including the development of clean coal technology and the purchase of offset credits. The acquisition of Vision Quest and its prospects for further developments have resulted in additional amounts of zero-emissions facilities consistent with TransAlta's strategy. Since 1990, TransAlta's worldwide emissions intensity (the amount of carbon dioxide (CO_2) emitted per MWh produced) decreased by 20 per cent.

Achieving the above goals will be dependent upon, but not limited to, certain risks and uncertainties. For further discussion, see Risk Factors and Risk Management in this MD&A.

SEGMENTED BUSINESS RESULTS

GENERATION Owns and operates hydro-, gas-, and coal-fired plants and related mining operations in Canada, the U.S., Mexico and Australia. At Dec. 31, 2002 Generation had 7,100 MW of generating capacity in operation and 951 MW under construction. Generation's results do not include results from wind-powered assets. Key performance indicators for Generation include availability, production and natural gas and electricity market prices.

Effective Jan. 1, 2002, TransAlta's organizational structure changed to combine the Generation and IPP business segments into one Generation segment. This was done to improve the corporation's operational capability and reliability through the sharing of resources and best practices across all generating assets. Prior period amounts have been reclassified to reflect the combination of these segments.

Available capacity increased during the year as a result of the completion of an upgrade at Centralia (32 MW) the commissioning of the Big Hanaford plant (248 MW), the previously described purchase of existing operational assets at the Sarnia plant (135 MW) and the purchase of the remaining interest in the Southern Cross facility (34 MW). This is offset by the decommissioning of the Pierce Power plant (154 MW) and Wabamun unit three (139 MW).

The results of the Generation segment are as follows:

Year ended Dec. 31	2002		2001		2000	
	Total	Per MWh	Total	Per MWh	Total	Per MWh
Revenues	**$1,673.9**	**$ 35.71**	$ 2,158.4	$ 48.90	$1,593.3	$ 39.20
Fuel and purchased power	**(703.6)**	**(15.01)**	(1,230.6)	(27.88)	(741.2)	(18.24)
Gross margin	**970.3**	**20.70**	927.8	21.02	852.1	20.96
Operating expenses:						
Operations, maintenance and administration	**346.3**	**7.39**	290.6	6.58	260.1	6.40
Depreciation and amortization	**196.3**	**4.19**	156.5	3.55	167.7	4.12
Asset impairment and equipment cancellation charges	**152.5**	**3.25**	118.8	2.69	-	-
Taxes, other than income taxes	**27.3**	**0.58**	18.7	0.42	23.9	0.59
Prior period regulatory decisions	**3.3**	**0.07**	(11.0)	(0.25)	(44.1)	(1.09)
EBIT before corporate allocations	**244.6**	**5.22**	354.2	8.03	444.5	10.94
Corporate allocations	**(70.6)**	**(1.51)**	(82.5)	(1.87)	(77.9)	(1.92)
EBIT	**$ 174.0**	**$ 3.71**	$ 271.7	$ 6.16	$ 366.6	$ 9.02

Generation's revenues are derived from the production of electricity, of which, on an annualized basis, approximately 90 per cent are based upon contracted prices, including capacity payments, and approximately 10 per cent are subject to market pricing. Revenues received under long-term contractual arrangements are not subject to major fluctuations in the spot price for electricity. For the year ended Dec. 31, 2002, long-term contracts covered 90 per cent of total production (2001 - 92 per cent; 2000 - 96 per cent) with the remaining production subject to market pricing.

The existing contracts have remaining terms ranging from one to 22 years. At Dec. 31, 2002, contracted production, as a percentage of potential production from existing assets and assets currently under construction, over the next five years is as shown below.

	2003	2004	2005	2006	2007
Contracted output (%)	85	79	79	73	69

Revenues are subject to seasonal variations: during the summer months, warmer temperatures result in less efficient fuel conversion rates (higher heat rates) and increased hydro production from spring run-off results in lower electricity prices.

Generation also derives revenue from the provision of ancillary services and the sale of steam . A breakdown of revenues and average pricing applicable to contract and merchant production is presented in the following table:

Year ended Dec. 31	2002		2001		2000	
	Revenue	Per MWh	Revenue	Per MWh	Revenue	Per MWh
Contract	**$ 1,448.2**	**$ 33.26**	$ 1,374.1	$ 33.23	$ 1,195.7	$ 30.47
Merchant	**171.0**	**51.64**	681.2	142.91	347.1	246.27
Ancillary services and other	**93.6**	**-**	103.1	-	50.5	-
Wabamun arbitration decision	**(38.9)**	**-**	-	-	-	-
	$ 1,673.9	**$ 35.71**	$ 2,158.4	$ 48.90	$ 1,593.3	$ 39.20

A reconciliation between production, revenue and EBIT for the years ended Dec. 31, 2001 and 2002 is presented below:

	Production (GWh)	Revenue	EBIT
Year ended Dec. 31, 2000	40,644	$1,593.3	$366.6
1999 regulatory decisions received in 2000	-	-	(44.1)
Wabamun unit four TSR settlement for 2000	-	-	11.0
Higher returns and incentives under PPAs	-	208.3	208.3
Increased hydro ancillary services	-	53.0	53.0
Decrease in hydro energy output	(240)	(17.9)	(17.7)
Acquisition of Centralia plant	2,785	155.0	47.3

Unplanned Centralia outages	-	95.7	(245.5)
Centralia hedge losses, expired in 2001	-	11.8	(124.2)
Commencement of operations at Poplar Creek plant	2,491	84.9	25.8
Disposal of Mildred Lake, Fort Nelson and Fort Saskatchewan plants	(1,713)	(86.6)	6.5
Monetization of Pierce Power plant	-	121.8	3.0
Other	169	(60.9)	(18.3)
Year ended Dec. 31, 2001	44,136	$2,158.4	$271.7
Net improved availability and production	2,538	91.1	53.5
New gas plants in service (Sarnia and Big Hanaford)	493	40.2	(13.1)
Accelerated Alberta thermal plant maintenance	(290)	(10.6)	(27.7)
Wabamun impairment and equipment cancellation charges	-	-	(152.5)
Lower market prices	-	(441.9)	(441.9)
Lower purchase power requirements	-	-	562.8
Wabamun arbitration decision	-	(38.9)	(38.9)
Impact of the Pierce Power plant monetization in 2001	-	(121.8)	(3.0)
Increased operations, maintenance and administration expense	-	-	(33.0)
Increased depreciation	-	-	(34.6)
Lower fuel costs per megawatt hour	-	-	39.4
Wabamun unit four TSR settlement and prior period regulatory decision	-	-	(14.3)
Other	-	(2.6)	5.6
Year ended Dec. 31, 2002	**46,877**	**$1,673.9**	**$174.0**

As discussed in Significant One-Time Items, the corporation recognized a pre-tax impairment charge of $110.0 million relating to the Wabamun plant, as the carrying value was determined to be in excess of fair value. TransAlta also cancelled the order for four natural gas turbines resulting in a $42.5 million pre-tax contract termination charge. In September 2001, TransAlta reassessed its investment in the 154 MW Pierce Power plant as a result of weak economic conditions. Revenue hedges that were expected to be effective were unwound and realized, resulting in the recognition of $121.8 million in revenue, partially offset by an asset impairment charge of $66.5 million and a recognition of anticipated future operating costs of $52.3 million.

As a result of the corporation's forward view of the electricity market and its positive experience with improvements at the Centralia plant, the corporation accelerated its Alberta thermal plant maintenance schedule. This was undertaken in order to improve reliability and increase availability in the future. This decision resulted in lower revenues and increased maintenance costs ($27.7 million pre-tax) in the fourth quarter of 2002.

As discussed in Significant One-Time Items, the Wabamun arbitration decision resulted in a $38.9 million pre-tax payment, excluding interest that was recorded as a reduction of revenue in the second quarter of 2002.

As discussed in Significant One-Time Items, the following prior period regulatory decisions impacted revenues in 2002, 2001 and 2000: the EUB rendered a negative decision of $3.3 million pre-tax with respect to TransAlta's hydro bidding, which was recorded in 2002; the EUB ruled that the Wabamun unit four outage qualified for relief under the TSR and ordered that TransAlta receive $11.0 million (pre-tax) in 2001; TransAlta received a negotiated settlement of $17.8 million (pre-tax) under the TSR in 2000; and the EUB announced an amendment to its Phase I decision (1999 Final Decision) that increased pre-tax earnings by $30.6 million in 2000.

For 2002, Generation achieved an availability rate of 88.4 per cent compared to 86.9 per cent in 2001. The increase is the result of improved operational performance at the thermal and gas plants, partially offset by the accelerated maintenance at the Alberta thermal plants and the Wabamun unit three outage. At various times during 2002, when the market price of electricity was lower than the variable costs of production at certain plants, the corporation reduced production at these plants, and purchased electricity from the market to fulfill contractual obligations (economic dispatch). During these periods of economic dispatch, the affected plants were available to generate the electricity if required.

In 2001, availability was negatively impacted by unplanned outages at the Centralia plant and the Wabamun unit four outage. In 2000, availability was negatively impacted by the Wabamun unit four outage.

	2002	2001	2000
Annual electricity production (GWh)	**46,877**	44,136	40,644

Generation's production increased by 2,741 gigawatt hours (GWh) in 2002 compared to 2001. The increase is the result of incremental production from the Sarnia and Big Hanaford plants, increased production from the Centralia plant, the return to service of Wabamun unit four, as well as increased thermal production and availability. This was partially offset by lost production resulting from accelerated Alberta thermal plant maintenance and economic dispatch decisions.

Production in 2001 increased over 2000 primarily as a result of a full year of production from the Centralia plant, which was acquired in May 2000, and increased production from the Poplar Creek plant which commenced commercial operations in January 2001. This was partially offset by decreased hydro production and lost production due to the sale of the Mildred Lake and Fort Nelson plants.

	2002	2001	2000
Revenue ($/MWh)	**35.71**	48.90	39.20

Revenue in 2002 decreased by $484.5 million ($13.19 per MWh) compared to 2001. Adjusted for the Wabamun arbitration and Pierce Power one-time items in 2002 and 2001 respectively, revenue was $1,712.8 million ($36.54 per MWh) in 2002 compared to $2,036.6 million ($46.14 per MWh) in 2001. The decline in revenue in 2002 reflects lower electricity spot prices, partially offset by improved production and availability.

In 2001 compared to 2000, increased revenues were realized from the Alberta PPAs, increased production from a full year of production from the Centralia and Poplar Creek plants, partially offset by the sale of the Mildred Lake and the Fort Nelson plants.

Fuel and purchased power decreased to $703.6 million ($15.01 per MWh) in 2002 from $1,230.6 million ($27.88 per MWh) in 2001 and $741.2 million ($18.24 per MWh) in 2000. Purchased power is the cost incurred to acquire electricity from the market to fulfill contracted commitments during planned and unplanned outages. Any electricity not required to fulfill these commitments is sold back into the market at spot prices.

		2002		2001		2000
Fuel	**$**	**671.5**	$	635.7	$	550.6
Purchased Power	**$**	**32.1**	$	594.9	$	190.6
Total	**$**	**703.6**	$	1,230.6	$	741.2

In 2002, purchased power declined significantly to $32.1 million from $594.9 million in 2001 and $190.6 million in 2000. The majority of the purchased power for 2002 was due to the economic dispatch decisions discussed earlier. In the year ended Dec. 31, 2001, 2,707 GWh of electricity were purchased totalling $594.9 million. Pre-tax losses as a result of these purchases were US$77.7 million (approximately Cdn$124 million) in 2001. The purchased power in 2001 and 2000 was the result of unplanned outages at Centralia.

Fuel costs, excluding purchased power, consist primarily of coal and natural gas costs. Total fuel costs, excluding purchased power, were $671.5 million ($14.32 per MWh) in 2002 compared to $635.7 million ($14.40 per MWh) in 2001 and $550.6 million ($13.55 per MWh) in 2000. TransAlta's average fuel costs per MWh are shown below:

	2002	2001	2000

Coal	**$ 11.70**	$	12.34	$	12.18
Gas	**$ 27.86**	$	26.16	$	23.95
Average fuel costs, excluding purchased power	**$ 14.32**	$	14.40	$	13.55

TransAlta is subject to fluctuations in natural gas and coal costs ; however , the majority of the coal used in generation is from coal reserves owned by TransAlta. This allows the corporation to control the cost of coal. As a result of cost reduction programs, TransAlta reduced coal costs by five per cent in 2002 compared to 2001. Fuel costs, excluding purchased power, on a per MWh basis, decreased in 2002 as a result of the decrease in coal costs, partially offset by increased natural gas costs. The increase in gas costs was due to higher natural gas market prices at the Big Hanaford plant, higher gas prices and heat rates at the Sarnia plant, and increased transportation costs. For contracted plants, a portion of the gas cost has been hedged by the corporation, and in some cases, the corporation has hedged plants' spark spreads. In certain contracted plants the gas cost is a flow through to the customer and is not hedged by the corporation; therefore , TransAlta is still subject to fluctuations in gas prices, but the increased gas costs are recovered through increased revenues. Gas costs for electricity to be sold in spot markets are matched to power sales and hedged accordingly.

Coal costs per MWh in 2001 were similar to 2000 while the increased gas costs per MWh in 2001 compared to 2000 reflect ed higher natural gas market prices.

In 2002, OM&A expenses increased by $55.7 million ($0.81 per MWh) over 2001. The increase represents the impact of the accelerated maintenance at the Alberta thermal plants, the commissioning of the Sarnia and Big Hanaford plants, increased business development costs, inventory obsolescence costs, and increased project management costs related to plants under construction, partially offset by cost reduction initiatives. OM&A in 2001 increased by $30.5 million ($0.18 per MWh) compared to 2000 as a result of the increased maintenance at the Centralia plant.

Depreciation and amortization increased by $39.8 million ($0.64 per MWh) in 2002 compared to 2001. The increase is a result of the addition of the Big Hanaford plant and increased capital projects at the thermal plants, including the scrubber project at Centralia. Depreciation and amortization decreased by $11.2 million ($0.57 per MWh) in 2001 over 2000 due to the sale of the Mildred Lake, Fort Nelson and Fort Saskatchewan plants, partially offset by a full year of operations at the Centralia plant and the commissioning of the Poplar Creek plant.

The increase in taxes other than income taxes in 2002 relates to higher property tax assessments by local municipalities on the majority of the corporation's plants.

ENERGY MARKETING: Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. These activities provide critical market knowledge to help identify growth opportunities and support corporate investment decisions. Key performance indicators for Energy Marketing include trading volumes, margins and VAR.

The Energy Marketing segment operates on behalf of Generation to sell electricity produced, purchase natural gas not covered by long-term contracts, establish long-term contracts for the sale of electricity and the purchase of natural gas, and purchase and sell transmission capacity to transmit electricity. The results of these arrangements and the costs to execute them are included in Generation's segment results.

Energy Marketing also uses energy derivatives, including physical and financial swaps, forward and future contracts and options to earn trading revenues and to gain market information. Trading activities and energy contracts that meet the definition of a derivative in the Financial Accounting Standards Board (FASB) Statement 133, Accounting for Derivative Instruments and Hedging Activities, are accounted for at fair value in accordance with Canadian and U.S. GAAP.

Derivatives are used to hedge the corporation's exposure to changes in electricity and natural gas prices. Under Canadian GAAP, settlement accounting is used for hedging activities if certain criteria are met. Under U.S. GAAP, hedging activities are accounted for in accordance with FASB Statement 133.

The results of Energy Marketing are as follows:

Year ended Dec. 31		**2002**		2001		2000
Gross revenues	**$**	**3,703.8**	$	2,694.7	$	1,280.3
Trading purchases		**(3,654.8)**		(2,533.7)		(1,202.5)
Net revenues		**49.0**		161.0		77.8
Operations, maintenance and administration		**15.1**		36.2		19.0
Depreciation and amortization		**2.5**		11.0		9.4
Taxes, other than income taxes		**0.1**		-		-
EBIT before corporate allocations		**31.3**		113.8		49.4
Corporate allocations		**(8.3)**		(6.6)		(7.1)
EBIT	**$**	**23.0**	$	107.2	$	42.3

The gross physical and financial settled sales transactions are as follows:

Electricity (GWh)			
Year ended Dec. 31	**2002**	2001	2000
Physical	**63,015**	18,504	6,365
Financial	**40,061**	9,115	3,135
	103,076	27,619	9,500

Gas (million GJ)			
Year ended Dec. 31	**2002**	2001	2000
Physical	**96.2**	30.6	42.1
Financial	**63.6**	68.7	93.6
	159.8	99.3	135.7

Gross trading sales volumes increased by 75,457 GWh of electricity and 60.5 million gigajoules (GJ) of gas in 2002 compared to 2001. Liquidity in the medium- to long-term markets remained low and as a result, Energy Marketing continued to have a low level of activity in these markets while TransAlta's activity levels in the short-term market increased. TransAlta's trading activity comprised mainly short-term transactions, the majority of which were settled within 90 days thereby limiting risk and maintaining low working capital requirements. The increase in gas trading volumes relates to the settlement of trading positions offset in early 2002 when the gas trading book was closed. In addition, the trading of heat rate swaps, which include a gas element and are therefore presented as settled gas transactions, increased in 2002.

The increased electricity trading volumes in 2001 compared to 2000 were in response to high market volatility and prices in the Pacific Northwest for the first five months of 2001.

		2002		2001		2000
Net revenues	**$**	**49.0**	$	161.0	$	77.8

Net revenues decreased by $112.0 million in 2002 due to significantly lower market prices and margins compared to 2001, particularly in the Pacific Northwest. As expected, increased market liquidity and pricing efficiencies in the short-term market in 2002 resulted in margins on individual trades being reduced. The 2001 Pacific Northwest prices were influenced by the process of deregulation in California, exacerbated by a drought in the Pacific Northwest and historically high natural gas prices. Net revenues in 2000 were lower than in 2001 for the reasons discussed above.

	2002	2001	2000
OM&A	**$ 15.1**	$ 36.2	$ 19.0

OM&A expense decreased by $21.1 million for the year ended Dec. 31, 2002 due to lower annual incentive compensation resulting from lower annual net revenue and EBIT as well as one-time costs associated with the acquisition of the remaining 50 per cent of Merchant Energy Group of the Americas, Inc. (MEGA) in June 2001. Expenses were higher in 2001 than in 2000 due to the one-time costs relating to the MEGA acquisition and higher incentive compensation.

Depreciation and amortization decreased by $8.5 million in 2002 compared to 2001. The decrease is due to $29.3 million of goodwill arising from the acquisition of MEGA, previously recorded as acquired intangibles, which is no longer being amortized. This treatment is in accordance with the new accounting standard issued by the CICA. Depreciation and amortization in 2001 was higher than in 2000 as a result of the increased goodwill resulting from the MEGA acquisition.

VAR is a measure to manage earnings exposure for Energy Marketing activities. The average daily VAR level in 2002 was approximately $2.6 million compared to $1.2 million in 2001. See additional discussion under commodity price risk in Risk Factors and Risk Management.

Energy Marketing's price risk management assets and liabilities represent the fair value of unsettled (unrealized) trading transactions. With the exception of transmission contracts, the fair value of all energy trading activities is based on quoted market prices. The fair value of physical transmission contracts is based on quoted market prices and a spread option valuation model. The fair value of financial transmission contracts is based upon statistical analysis of historical data.

The following table illustrates movements in the fair value of the corporation's price risk management assets during 2002:

Fair value of net price risk management assets outstanding at Dec. 31, 2001	$ 25.8
Fair value of new contracts entered into during the period	(2.7)
Changes in fair values attributable to market price and other market changes	7.6
Contracts realized or settled during the period	(36.6)
Changes in fair values attributable to changes in valuation techniques and assumptions	-

Fair value of net price risk management liabilities outstanding at Dec. 31, 2002	**$**	**(5.9)**

The source of the valuations of the above contracts and maturities over each of the next five calendar years and thereafter is as follows:

	2003	2004	2005	2006	2007	2008 and thereafter	Total
Prices actively quoted	$ (17.6)	$ 3.3	$ 3.2	$ 2.1	$ 1.5	$ -	$ (7.5)
Prices based on models	1.6	-	-	-	-	-	1.6
Asset (liability)	$ (16.0)	$ 3.3	$ 3.2	$ 2.1	$ 1.5	$ -	$ (5.9)

In 2002, TransAlta responded to a number of inquiries from various U.S. State and Federal bodies regarding trading activities in California and states in the Pacific Northwest during 2000 and 2001. TransAlta believes it operated in accordance with all applicable laws, rules, regulations and tariffs. No significant developments have occurred on these issues as a result of TransAlta's responses.

In the fourth quarter of 2002, two class action lawsuits on behalf of all persons and businesses in the states of Oregon and Washington were initiated in respect of alleged unlawful practices in the purchase and sale of wholesale energy. TransAlta believes these are without merit and will vigorously defend these claims.

In 2000, TransAlta made a provision of US$28.8 million against US$58.0 million owing from the California Independent System Operator and the California Power Exchange. During 2001, US$5.0 million was collected. The net amount has been reclassified to long term, as collection is no longer expected in 2003, although ultimate collection of the net receivable is still expected. On Dec. 12, 2002, a U.S. Federal Energy Regulatory Commission (FERC) Administrative Law Judge proposed that TransAlta receive approximately US$44.0 million ; however , FERC has indicated that further adjustments in respect of power and gas prices may occur, which could result in further alterations of the amount TransAlta is to receive. As a result, TransAlta has not adjusted the amount receivable or the provision.

TransAlta acquired the remaining 50 per cent of MEGA in June 2001 for cash consideration of US$0.3 million

(Cdn$0.4 million). The initial 50 per cent of MEGA was purchased in June 2000 for cash consideration of US$12.5 million (Cdn$18.6 million). Subsequent to the acquisition, one-time costs of $13.9 million were incurred, comprised primarily of severance of $3.9 million and long-term employment incentives in the amount of $8.5 million. TransAlta continues to use MEGA as a platform on which to expand trading activities into eastern U.S. regions. MEGA has been amalgamated with TransAlta Energy Marketing U.S. Inc., a subsidiary of TransAlta Energy Corporation (TransAlta Energy) and is therefore included in the Energy Marketing business segment.

NET INTEREST EXPENSE, OTHER EXPENSE AND FOREIGN EXCHANGE

Year ended Dec. 31	**2002**	2001	2000
Gross interest expense	**$ 172.9**	$ 170.3	$ 180.0
Interest income	**(8.7)**	(24.2)	(23.8)
Capitalized interest	**(79.1)**	(48.3)	(39.8)
Allocated to discontinued operations	**(2.4)**	(9.7)	(25.0)
Net interest expense	**82.7**	88.1	91.4
Other expense (income)	**(0.1)**	(1.5)	1.1
Foreign exchange gains	**(1.2)**	(0.8)	(0.1)
	$ 81.4	$ 85.8	$ 92.4

Year ended 2000	$ 92.4
Increased debt levels, net of interest on Alberta D&R deferral accounts	5.4
Increased capitalized interest	(8.5)
Lower effective interest rates	(14.6)
Decreased allocations to discontinued operations	15.3
Other	(4.2)
Year ended 2001	$ 85.8
Increased debt levels, net of interest on Alberta D&R deferral accounts	22.2
Increased capitalized interest	(30.8)
Lower effective interest rates	(3.2)
Decreased allocations to discontinued operations	7.3
Other	0.1
Year ended 2002	**$ 81.4**

In June 2002, the corporation issued US$300.0 million of senior notes under a US$1.0 billion shelf registration statement filed May 14, 2002. The proceeds of the issuance were used to repay short-term debt and U.S. denominated commercial paper. The notes bear interest at 6.75 per cent and mature in July 2012.

Net interest expense decreased by $5.4 million in 2002 as a result of an overall decline in short-term interest rates and higher capitalized interest, partially offset by a higher proportion of debt subject to long-term interest rates and receipt of the $180.3 million interest-bearing receivable from Aquila Networks Canada that arose from the sale of the Alberta D&R operation.

Net interest expense decreased by $3.3 million in 2001 compared to 2000. Higher debt levels resulting from the acquisition of the Centralia plant, the commencement of commercial operations at the Poplar Creek plant and increased capital expenditures were offset by the proceeds on the disposal of the Alberta D&R operation, increased capitalized interest and lower interest rates.

OUTLOOK

Net interest expense is expected to increase due to the decreased capitalized interest on assets under construction as the Big Hanaford plant commenced commercial operations in August 2002, and the Sarnia, Campeche and Chihuahua plants will commence commercial operations in 2003. During 2002, the corporation capitalized interest of $79.1 million as a result of the significant construction activity during the year. Upon completion of these plants, interest will no longer be capitalized. Incremental interest expense in respect of these plants in 2003 will be approximately $80 million. Net interest expense will also increase due to the acquisition funding for CE Gen plus the interest related to approximately US$500 million of assumed non-recourse debt. Capitalized interest for 2003 will relate to the construction of the Genesee 3 project and the remaining construction on the Sarnia, Campeche and Chihuahua plants.

PREFERRED SECURITIES DISTRIBUTIONS

Year ended Dec. 31	**2002**	2001	2000
Preferred securities distributions, net of tax	**$ 20.9**	$ 13.1	$ 12.8

The increase in preferred securities distributions, net of tax, reflect s the issuance of $175.0 million of 7.75 per cent preferred securities in November 2001.

OUTLOOK

2003 preferred securities distributions are expected to be similar to 2002 levels, assuming no change in principal amounts outstanding.

INCOME TAXES

Year ended Dec. 31	**2002**	2001	2000
Income taxes	**$ 18.1**	$ 89.9	$ 128.5
Effective tax rate (%)	**15.6**	30.7	40.6

Income taxes decreased by $71.8 million for the year ended Dec. 31, 2002 due to lower pre-tax earnings as well as the impact of the Wabamun impairment charge and the turbine cancellation charges, which were recognized at the marginal rate. The decrease also reflects the benefit of previously unrecognized tax losses that were recognized during the year as it became more likely than not that they would be utilized. The effective income tax rate, expressed as a percentage of earnings from continuing operations before income taxes and non-controlling interests, decreased to 15.6 per cent in 2002 from 30.7 per cent in 2001. The effective tax rate in 2002 reflects the impact of the issues discussed above.

The decrease in the effective tax rate in 2001 compared to 2000 reflects the reduction in Canadian tax rates, lower non-deductible items, and an increase in the manufacturing and processing tax credit.

OUTLOOK

Income taxes are expected to increase in 2003 due to higher pre-tax earnings from operations. Assuming a similar geographic distribution of earnings and no material changes in tax rates, the corporation anticipates an effective tax rate for 2003 of approximately 30 per cent.

NON-CONTROLLING INTERESTS

Year ended Dec. 31	**2002**	2001	2000
Earnings attributable to non-controlling interests	**$ 20.1**	$ 20.6	$ 41.6

The decrease in earnings attributable to non-controlling interests in 2002 compared to 2001 reflects the redemption of the preferred shares of TransAlta Utilities Corporation (TransAlta Utilities) for $121.6 million in September 2001, resulting in lower subsidiary preferred share dividends, partially offset by increased earnings from the 49.99 per cent non-controlling interest in TransAlta Cogeneration, L.P. (TA Cogen) due to the addition of the Fort Saskatchewan plant in 2001.

The decrease in 2001 compared to 2000 is due primarily to the minority interest portion of the fair value liability of a natural gas swap between TA Cogen and the corporation entered into in December 2000 which was charged to income in 2000. The swap transaction provides TA Cogen with fixed price gas for both the Mississauga and Ottawa plants until Dec. 31, 2005. The swap was entered into by TransAlta to stabilize cash distributions of the limited partnership for five years at levels consistent with previous years. Increased earnings from TransAlta Power, L.P.'s (TransAlta Power) 49.99 per cent limited partnership interest in TA Cogen were offset by the redemption of the 4.0 per cent to 7.7 per cent Series and 8.4 per cent Series of preferred shares of TransAlta Utilities Corporation in September 2001 and March 2000, respectively.

OUTLOOK

No significant changes in non-controlling interests are expected in 2003 assuming current investment levels.

DISCONTINUED OPERATIONS

		Date Sold	**2002**	2001	2000
Transmission	- earnings from operations	April 29, 2002	**$ 12.8**	$ 44.4	$ 44.3
	- gain on disposition		**120.0**	-	-
Edmonton Composter	- earnings from operations	June 29, 2001	**-**	0.7	0.7
	- write-down of carrying value		**-**	-	(17.9)
Alberta D&R	- earnings from operations	Aug. 31, 2000	**-**	-	33.3
	- gain on disposition		**-**	-	262.4
New Zealand	- earnings from operations	March 31, 2000	**-**	-	10.8
	- gain on disposition		**-**	-	22.3
			$ 132.8	$ 45.1	$ 355.9

TRANSMISSION

As discussed in Significant One-Time Items, TransAlta sold its Transmission operation in April 2002 for proceeds of $820.7 million. The disposal resulted in an after-tax gain on sale of $120.0 million ($0.71 per common share).

EDMONTON COMPOSTER

As discussed in Significant One-Time Items, TransAlta sold its Edmonton Composter facility for proceeds of $97.0 million, which approximated its book value.

ALBERTA DISTRIBUTION AND RETAIL

As discussed in Significant One-Time Items, TransAlta sold its Alberta D&R operation in August 2000 for net proceeds of $857.3 million and an after-tax gain on sale of $262.4 million ($1.55 per common share).

NEW ZEALAND

As discussed in Significant One-Time Items, the New Zealand business operations were sold in March 2000 for proceeds of NZ$832.5 million (approximately Cdn$605 million) and an after-tax gain on sale of $22.3 million ($0.13 per common share).

CONSOLIDATED BALANCE SHEETS

The following chart outlines significant changes in the consolidated balance sheets between Dec. 31, 2002 and Dec. 31, 2001:

Summary of Significant Changes *(in millions of Canadian dollars)*	**Increase/ (Decrease)**	**Explanation**
Cash and cash equivalents	$ 81.3	*Refer to Consolidated Statements of Cash Flows.*
Accounts receivable and other	(156.9)	*Decrease primarily due to collection of receivables related to Pierce Power hedges ($82.0 million), reclassification of California receivables to long-term (US$24.2 million) and collection of the receivable related to the sale of the Transmission business ($31.7 million).*
Materials and supplies, at average cost	27.2	*Higher coal inventory balances as a result of second and third quarter economic dispatch decisions, increased coal production and advanced maintenance at the Alberta thermal plants.*
Long-term receivables	(181.5)	*Receipt of amount due from Aquila Networks Canada relating to the sale of the discontinued Alberta D&R operation ($180.3 million) and reclass of sulphur tax abatement ($60.9 million) to current receivables, offset by reclassification of California receivables to long-term (US$24.2 million).*
Property, plant, and equipment, net of accumulated depreciation	(59.7)	*Capital expenditures and construction activity during the period and acquisition of Vision Quest, more than offset by depreciation, the sale of the Transmission business, the impairment charge relating to the decommissioning of the Wabamun plant and equipment cancellation charges.*
Goodwill	27.2	*Acquisition of Vision Quest in December 2002.*
Future income tax assets	56.6	*2001 U.S. operating losses that are expected to be recovered in future years.*
Other assets	29.5	*Long-term prepayments related to the Sarnia plant, financing costs related to US$300.0 million debt issuance and financing costs related to the Mexican projects.*

Short-term debt	(247.2)	*Repayment with a portion of the proceeds from US$300.0 million debt issuance and proceeds from disposal of the Transmission operation, offset by capital expenditures.*
Accounts payable and accrued liabilities	(155.3)	*Decrease due to lower capital expenditures.*
Price risk management liabilities (current and long-term)	41.3	*Decrease in margins on energy trading activities.*
Long-term debt (including current portion)	195.5	*US$300.0 million debt issuance, offset by maturity of debentures of $100.0 million and net decrease in long-term commercial paper repaid with proceeds on disposal of the Transmission business.*
Non-controlling interests	(18.0)	*Acquisition of remaining interest in Southern Cross Energy ($7.2 million) and decreased non-controlling interest in TA Cogen as a result of distributions in excess of net income.*
Shareholders' equity	49.9	*Net earnings and issuance of common shares for Vision Quest acquisition, partially offset by dividends and net redemption of common shares.*

LIQUIDITY AND CAPITAL RESOURCES

TransAlta raises substantially all external capital to be invested in the various business units and affiliated or subsidiary companies as required. This strategy allows TransAlta to gain access to sufficient capital at the lowest overall cost to finance its growth strategy and to provide financial flexibility. Historically, external financing has been obtained from borrowings under credit facilities, proceeds from the disposal of non-core assets and the issuance of debt, preferred securities and equity. Internally, capital is also raised through operations. A summary of cash flows is as follows:

Year ended Dec. 31	**2002**	2001	2000
Cash, beginning of year	**$ 62.0**	$ 53.8	$ 75.3
Cash flow from (used in):			
Operating activities	**437.7**	715.6	198.7
Investing activities	**(36.2)**	(1,076.9)	(205.0)
Financing activities	**(320.9)**	368.7	(2.7)
Translation of foreign currency cash	**0.7**	0.8	(12.5)
Cash, end of year	**$ 143.3**	$ 62.0	$ 53.8

TransAlta increased its cash balance by $81.3 million in 2002 compared to an increase of $8.2 million in 2001 and a decrease of $21.5 million in 2000. Significant changes were as follows:

OPERATING ACTIVITIES Operating activities after changes in non-cash working capital provided cash of $437.7 million in 2002 compared to $715.6 million in 2001 and $198.7 million in 2000.

The decrease in 2002 was a result of the impact of the Wabamun arbitration and prior period regulatory decisions, increased working capital requirements due to the timing of the ancillary revenue settlement ($49.9 million), timing of accounts receivable relating to the Alberta Power Pool for Generation due to deregulation on Jan. 1, 2001 ($170.0 million), and the final installment of 2001 income taxes paid in the first quarter of 2002 ($109.0 million). In 2000, significantly increased working capital requirements resulted from deferred accounts receivable related to the sale of the discontinued Alberta D&R operation and increased trade receivables related to Centralia production and Energy Marketing activities.

INVESTING ACTIVITIES Investing activities used cash of $36.2 million in 2002 compared to $1,076.9 million in 2001 and $205.0 million in 2000.

In 2002, additions to capital assets totalled $945.8 million and consisted primarily of the completion of the Big Hanaford plant and continued construction of the Sarnia, Campeche and Chihuahua plants. Acquisitions of $40.1 million consisted of the purchase of the remaining interests in Vision Quest and Southern Cross Energy.

In 2001, capital expenditures of $1,246.5 million related primarily to the installation of the scrubber at the Centralia plant and the continued construction activities at the Big Hanaford, Sarnia, Campeche and Chihuahua plants.

In 2000, capital expenditures of $795.0 million consisted primarily of continued construction of the Poplar Creek plant, the construction of the scrubber at the Centralia plant and capital maintenance at the Alberta plants. Cash used for acquisitions totalled $880.1 million, consisting primarily of the acquisition of the Centralia plant for $868.7 million and the acquisition of MEGA for $18.6 million, net of cash acquired of $7.2 million.

Cash provided by disposals and the sale of capital assets in 2002 totalled $820.3 million comprised primarily of proceeds from the sale of the discontinued Transmission operation in April 2002. Proceeds were used to repay short- and long-term debt.

Cash provided by disposals and the sale of capital assets in 2001 was $236.6 million comprised primarily of proceeds of $97.0 million from the sale of the Edmonton Composter, $60.3 million from the sale of the Mildred Lake plant, $44.1 million from the sale of the Fort Nelson plant and $35.0 million from the sale of half of the corporation's interest in the Fort Saskatchewan plant.

Cash provided by disposals in 2000 was $1,367.0 million of which $723.6 million related to the disposal of the Alberta D&R operation and NZ$832.5 million (approximately Cdn$605 million) related to the disposal of the New Zealand operations in 2000.

In August 2002, long-term receivables in the amount of $180.3 million due from Aquila Networks Canada that arose from the sale of the Alberta D&R operation were collected in full.

In 2001, cash used for long-term receivables related primarily to an amount paid under an emissions reduction program that will be returned if emissions from the Centralia plant are reduced to a certain level by 2004.

In 2000, restricted investments of $86.8 million matured.

FINANCING ACTIVITIES Financing activities used cash of $320.9 million compared to providing cash of $368.7 million in 2001 and $2.7 million used in 2000.

In 2002, the issuance of US$300.0 million in senior notes was more than offset by the net repayment of short-term debt ($247.1 million), repayment of long-term debt ($454.5 million), cash dividends ($115.5 million), and the net redemption of common shares ($48.1 million).

In 2001, cash used for the $122.1 million redemption of preferred shares of a subsidiary, cash dividends of $149.6 million, net redemption of common shares of $30.3 million, distributions to non-controlling interests of $26.3 million and net distributions on preferred securities of $23.4 million were offset by an increase in short-term debt of $61.9 million, a net increase of $497.2 million in long-term debt and the net proceeds from the issuance of preferred securities of $169.4 million. The net addition to long-term debt and the proceeds from the preferred securities issuance were used to finance the significant capital expenditures during the year.

In 2000, cash used for the $158.4 million of dividends paid on common shares, $146.8 million redemption of preferred shares of a subsidiary, dividends and distributions to non-controlling interests of $42.8 million, and net redemption of common shares of $19.3 million was offset by an increase of $255.7 million in short-term debt, and net issuances of $126.2 million in long-term debt.

In 2002, TransAlta repaid the following senior secured debt of TransAlta Utilities Corporation:

	Maturity	Rate	Amount
Debentures	2002	8.70%	$ 100.0

In 2002, under the terms of the Normal Course Issuer Bid, the corporation purchased for cancellation 2.0 million (2001 - 2.0 million; 2000 - 1.6 million) common shares at an average price of $20.40 (2001 - $23.93; 2000 - $15.25).

TransAlta's dividends per common share were $1.00 in 2002, 2001 and 2000.

FINANCING ARRANGEMENTS TransAlta Corporation raises capital in the Canadian and U.S. markets. TransAlta has the following financing arrangements in place:

- US$1.0 billion shelf registration program, with US$300.0 million senior notes issued in June 2002 bearing 6.75 per cent interest. This facility expires in May 2004, and is expected to be renewed;
- $1.5 billion medium-term note program, no amount has been issued since its renewal on Sept. 26, 2001. This facility expires in September 2003, and is expected to be renewed;
- $1.0 billion commercial paper program, with $374.8 million issued at Dec. 31, 2002. This program does not expire;
- $1.2 billion committed syndicated bank credit facility, with $157.3 million utilized at Dec. 31, 2002. This facility expires in June 2003, and is expected to be renewed;

- $487.4 million of additional bank credit facilities, with $234.0 million utilized at Dec. 31, 2002. $437.4 million of these facilities are non-committed; and ,
- $300.0 million committed 364-day revolving facility was entered into in February 2003.

TransAlta Corporation issued $175.0 million of 7.75 per cent preferred securities on Nov. 29, 2001. It is the corporation's expectation that future financing requirements, including financing requirements in foreign jurisdictions, will be met primarily through raising capital at the TransAlta Corporation level. In addition to the above facilities, non-recourse project financing of US$133.6 million has been arranged for the Campeche project.

CASH REQUIREMENTS In 2003, cash will be provided from operations as well as a combination of new debt, preferred securities, equity and/or the sale of non-core assets. Future cash requirements include additions to capital assets, acquisitions, as well as dividend payments and refinancing of short-term and maturing senior debt.

In 2003, capital expenditures are necessary to maintain and improve the output from existing facilities ($325 million), fund the Genesee 3 project ($275 million), complete the construction of the Campeche and Chihuahua plants ($170 million) and fund other growth projects ($60 million). The acquisition of CE Gen will initially be financed with short-term debt and subsequently refinanced with a combination of cash flow from operations, long-term debt, preferred securities and equity. In addition, $355.4 million of existing debt is required to be refinanced during 2003.

Short-term liquidity is provided through cash flow from operations and utilization of various credit facilities. At Dec. 31, 2002, there were approximately $1 billion of funds available under credit facilities. Cash provided by operations in 2002 was $437.7 million.

In January 2001, the corporation issued $250.0 million of medium-term notes at an interest rate of 6.05 per cent repayable in five years. In May 2001, the corporation issued $225.0 million of medium term notes at an interest rate of 6.90 per cent repayable in 10 years. The proceeds were used to repay short-term debt.

Long-term funding is provided through the maintenance of high-quality credit ratings and a carefully managed capital structure, which together create a strong balance sheet and ready access to capital markets at competitive rates. The corporation's objective is to manage the maturities of the various securities on issue such that no more than 15 per cent of the total outstanding securities mature in any one year.

The corporation's targets are to maintain its credit ratings at strong investment grade levels and maintain a capital structure of 50 per cent debt to total capitalization. The corporation's capital structure consisted of the following components at Dec. 31, 2002, 2001 and 2000:

	2002	2001	2000
Debt to invested capital (%)	**50.9**	52.3	48.0

	2002		2001		2000	
Debt, net of cash and interest-earning investments	**$ 2,853.3**	51%	$2,986.3	52%	$2,421.9	48%
Preferred securities	**451.7**	8%	452.6	8%	292.0	6%
Other non-controlling interests	**263.0**	5%	281.0	5%	253.4	5%
Preferred shares of a subsidiary	**-**	-	-	-	121.6	2%
Common shareholders' equity	**2,039.6**	36%	1,989.7	35%	1,957.4	39%
	$ 5,607.6	100%	$ 5,709.6	100%	$5,046.3	100%

With the purchase of 50 per cent interests in CE Gen and Genesee 3, the debt to invested capital ratio has increased since Dec. 31, 2002. It is TransAlta's intention to return to a 50 per cent debt to invested capital ratio through utilizing cash from operations, the sale of selected assets and the issuance of common shares.

Additional key financial ratios were as follows:

	2002	2001	2000
Cash flow to interest[1]	**3.8x**	4.8x	4.4x
Cash flow to total debt[2]	**18%**	25%	26%

[1] Cash flow from operations before changes in working capital and gross interest expense divided by gross interest expense.

[2] Cash flow from operations before changes in working capital divided by two-year average of total debt.

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

	2003	2004	2005	2006	2007	2008 and thereafter	Total

Long-term debt[1]	$ 355.4	$ 146.9	$ 247.4	$ 364.4	$ 15.7	$ 1,576.8	$ 2,706.6
Operating leases	6.7	5.7	5.5	4.4	3.2	26.7	52.2
Turbine purchase commitments	6.2	46.0	1.2	-	-	-	53.4
Mining agreements	20.0	20.0	20.0	20.0	20.0	357.5	457.5
Total contractual cash obligations	$ 388.3	$ 218.6	$ 274.1	$ 388.8	$ 38.9	$ 1,961.0	$ 3,269.7

[1] Includes capital lease obligations.

In addition, the corporation has entered into a number of long-term power sales, gas purchase and transportation agreements in the normal course of operations as hedges of its operations.

In the normal course of operations, TransAlta and certain of its subsidiaries enter into agreements to provide financial or performance assurances to third parties. This includes guarantees, letters of credit and surety bonds which are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for Energy Marketing trading activities, treasury hedging, Generation construction projects, equipment purchases and mine reclamation obligations.

At Dec. 31, 2002, the corporation had $161.7 million, US$144.4 million and 35.2 million pesos in letters of credit outstanding. The letters of credit were issued to counterparties that have credit exposure to certain subsidiaries. If a subsidiary does not pay amounts due under the covered contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. Any amounts owed by the corporation's subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire in 2003.

At Dec. 31, 2002, the corporation issued a surety bond in the amount of US$156.7 million in support of future site reclamation liabilities at the Centralia mine. A provision for reclamation liabilities is included in the deferred credits and other long-term liabilities (Note 12). The surety bond expires in 2005.

TransAlta also guaranteed payments for its subsidiaries involved in hedging and trading activities. These guarantees are provided to counterparties in order to facilitate physical and financial transactions in various derivatives. To the extent liabilities exist for trading activities, they are included in the consolidated balance sheet. To the extent liabilities exist for hedging activities, they are disclosed in Note 20. The limit under these guarantees at Dec. 31, 2002 for trading and hedging activities was $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The exposure at Dec. 31, 2002 under these guarantees was approximately $475 million. Certain contracts contain provisions that may require collateral to be provided if certain triggers in the contract are met such as fluctuations in commodity prices or creditworthiness. In the absence of any credit limits granted by TransAlta's counterparties, TransAlta's maximum collateral requirements would have been $492.0 million at Dec. 31, 2002 if the corporation's credit ratings were below investment grade. Collateral available was approximately $1 billion. See discussion under liquidity risk in Risk Factors and Risk Management.

TransAlta provided guarantees to counterparties for obligations of various subsidiaries for performance and payment of obligations. In the event of the subsidiaries' inability to meet the obligations, TransAlta would be obligated to make such payments. To the extent obligations existed under these guarantees at Dec. 31, 2002, they are included in accounts payable and accrued liabilities. The limit under these guarantees at Dec. 31, 2002 was $693.8 million.

TransAlta guaranteed the debt of $269.4 million at Dec. 31, 2002 for the Windsor and Campeche plants. The debt is recorded on TransAlta's consolidated balance sheets. The subsidiaries are required to comply with certain financial covenants as specified in the debt agreements. In the event of default, TransAlta would be obligated to pay the principal and any related interest. Currently, the subsidiaries are in compliance with all covenants, and management does not estimate any difficulties in continuing to maintain compliance. The US$133.6 million of debt related to the Campeche plant will become non-recourse to the corporation upon commencement of commercial operations, which is expected to occur in the first quarter of 2003, and the achievement of certain performance tests, which is expected to occur in the second half of 2003.

At Dec. 31, 2002, the credit ratings for the corporation's various securities and TransAlta Power's units as determined by Standard & Poor's (S&P), the Dominion Bond Rating Service (DBRS) and Moody's rating services were as follows:

Credit Ratings

	S&P	**DBRS**	**Moody's**
TransAlta Corporation			
Issuer rating	BBB+		Baa 1
Commercial paper		R1 (low)	
Senior unsecured debentures	BBB+	BBB (high)	(P) Baa 1
Preferred securities / stock	BBB-	Pfd-3 (high) y	(P) Baa 3
TransAlta Utilities Corporation			
Issuer rating	BBB+		
Secured debt	A-	A (low)	
TransAlta Power, L.P.*	SR-1		

** Non-controlling partner in TransAlta's subsidiary, TransAlta Cogen*

In May 2002, Moody's downgraded TransAlta Corporation's issuer rating from A3 and assigned prospective ratings of (P) Baa 1 and (P) Baa 3 to the corporation's senior unsecured debt and first preferred shares, respectively, under the corporation's US$1.0 billion shelf registration. In December 2002, DBRS downgraded TransAlta Corporation's credit ratings on senior unsecured debentures and preferred securities from A (low) and Pfd (low) y, respectively; and TransAlta Utilities' credit ratings on secured debentures from A. The downgrades reflect weak economic performance in the markets in which TransAlta operates. The downgrades do not trigger early repayment under the terms of any of the debt agreements.

In January 2003, Moody's placed TransAlta Corporation's rating under review for possible downgrade; S&P placed both ratings of TransAlta Corporation and TransAlta Utilities on credit watch; and DBRS changed their rating trend for both TransAlta Corporation and TransAlta Utilities from stable to negative. S&P affirmed the SR-1 stability rating for TransAlta Power on Jan. 15, 2003.

OFF-BALANCE SHEET ARRANGEMENTS The United States Securities and Exchange Commission (SEC) requires disclosure 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. The corporation has no such off-balance sheet arrangements.

Under Canadian GAAP, most derivatives used in hedging relationships are not recorded on the balance sheet (Note 1(O)). Gains or losses during the term of the hedge are deferred and recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The fair values of these derivatives are disclosed in Note 20 to the consolidated financial statements. The corporation also enters into long-term electricity purchase and sale, gas purchase and transportation agreements in the normal course of operations. These contracts are not recorded on the balance sheet under Canadian GAAP. Under U.S. GAAP, certain of these contracts meet the definition of a derivative, and would require mark-to-market accounting, but are eligible for the normal purchase and sale exemption under the Financial Accounting Standards Board (FASB) Statement 133. This exemption is available as electricity cannot be stored in significant quantities and due to the requirement for electricity generators to maintain sufficient capacity to meet customers' demands, and is also available for physically settled commodity contracts if certain criteria are met.

Information regarding guarantees has been disclosed in the Liquidity and Capital Resources section.

RELATED PARTY TRANSACTIONS

For the period November 2002 to November 2007, TA Cogen entered into a transportation swap transaction with a wholly owned subsidiary of TransAlta Corporation. The business purpose of the transportation swap was to provide TA Cogen with the delivery of fixed-price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. This stabilizes cash distributions in TA Cogen and thereby preserves the value of the limited partnership as a financing vehicle of TransAlta Corporation. The notional gas volume in the transaction was the total delivered fuel for both facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract with an external third party.

In 2001, the corporation sold its 60 per cent interest in its Fort Saskatchewan plant to TA Cogen. Total cash consideration to the corporation was $35.0 million in respect of the 30 per cent interest effectively sold to the minority interest in TA Cogen. The corporation recorded a pre-tax gain of $6.2 million. The business purpose of the arrangement was to realize a portion of the inherent value of the plant and provide cash for future growth initiatives while retaining control and operation of the asset through a management agreement with TA Cogen. The exchange amount was determined based on an estimate of the future net cash flows of the plant and approved by the independent directors of TA Cogen. There are no ongoing contractual commitments or arrangements resulting from this sale apart from the provision of operational and management services under normal commercial terms.

In 2000, TA Cogen entered into a fixed-for-floating gas swap transaction with TransAlta Energy, for a 61-month period starting Dec. 1, 2000. The business purpose of the swap was to provide TA Cogen with fixed-price gas for two of its plants over the period of the swap to stabilize cash distributions. The floating prices associated with the plants' long-term fuel supply agreements were transferred to TransAlta Energy's account. The notional gas volume in the transaction was the total delivered fuel for both facilities. As consideration and in negotiation, TA Cogen transferred the right to incremental revenues associated with curtailed electrical production and subsequent higher revenue gas sales to TransAlta Energy. Exchange amounts were based on the fair value of the contract and approved by the independent directors of TA Cogen.

In 1998, the corporation sold a 49.99 per cent interest in three Ontario cogeneration plants held by TA Cogen to TransAlta Power. The corporation is obligated to purchase all of TransAlta Power's interest in TA Cogen on Dec. 31, 2018 at the fair market value on that date. Accordingly, the gain of $160.3 million is being deferred and amortized on a straight-line basis over the period to Dec. 31, 2018. The business purpose of the arrangement was to realize the inherent value of the plants in order to provide cash for future growth initiatives while retaining control and operation of the assets. The exchange amount was determined based on the fair value of the plants at the time of the transaction and was approved by the independent directors of TA Cogen.

RISK FACTORS AND RISK MANAGEMENT

TransAlta uses a multi-level risk management oversight structure to manage the corporation's various risk and energy trading exposures.

The Audit and Environment (A&E) Committee of the Board of Directors oversees corporate-wide risk management through review of TransAlta's overall business risks. The Chief Financial Officer (CFO) reports to the A&E Committee and is responsible for ensuring compliance with TransAlta's financial and commodity risk exposure management policies. These policies include limits on exposures (commodity prices, currency, credit and interest rates), reporting practices and other procedures necessary for the corporation to manage and control its financial and commodity exposures.

The Exposure Management (EM) Committee is chaired by the CFO and is comprised of the Directors of Financial Operations for each business unit, the Vice-President and Treasurer, Vice-President and Comptroller, Director of Internal Audit, Vice-President of TransAlta Energy Marketing and the Manager of Treasury Operations. The EM Committee is responsible for the review, monitoring and reporting on compliance of these financial and commodity risk exposure management policies.

The following addresses some, but not all, risk factors that could affect TransAlta's future results. A discussion of critical estimates made in the application of accounting policies is provided in the Critical Accounting Policies and Estimates section that follows.

COMMODITY PRICE RISK The corporation has exposure to movements in certain commodity prices including electricity and natural gas in both its electricity generation and proprietary trading businesses. A significant portion of the coal used in electricity generation is from coal reserves owned by TransAlta, thereby limiting the corporation's exposure to fluctuations in the market price of coal.

Electricity generation is exposed to price fluctuations of electricity sold to the market and natural gas used in generating electricity. In addition to the PPAs, the corporation has entered into a variety of short- and long-term contracts to limit its exposure to short-term price movements and maximize overall revenues. In 2002, 90 per cent (2001 - 92 per cent) of total output was at contractually fixed prices, 62 per cent (2001 - 68 per cent) of TransAlta's cost of gas used in generating electricity was contractually fixed or passed through to customers and 100 per cent (2001 - 100 per cent) of the corporation's purchased coal costs were contractually fixed. In the event of an unplanned plant outage or other similar event, however, the corporation is exposed to electricity prices on purchases of electricity from the market to fulfill its supply obligations under these short- and long-term contracts. The corporation actively mitigates this exposure through continued and proper maintenance of its electricity generating plants, force majeure clauses negotiated in the contracts, trading activities and insurance.

The corporation's proprietary trading of gas and electricity is limited, strictly controlled and managed through the use of VAR methodologies.

VAR is the primary measure used to manage Energy Marketing'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 the corporation's 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 earnings and VAR to measure the potential effects of various market events that could impact earnings, including substantial fluctuations in commodity prices, volatility of those prices, and relationships between markets.

The corporation estimates 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.

An emerging view of VAR is to look at the number on a 99 per cent confidence interval over a 10-day holding period. For comparison purposes, the following table provides this average daily VAR of the corporation's marketing portfolio for 2002 and 2001:

	2002	2001
10-day average VAR - 99 per cent confidence level	**$6.6**	$3.2

CURRENCY RATE EXPOSURE The corporation has exposure to various currencies as a result of its investments and operations in foreign jurisdictions and the acquisition of equipment and services from foreign suppliers. The corporation has exposures primarily to the U.S. and Australian currencies. These exposures are managed through the use of a variety of hedging instruments including cross-currency interest rate swaps and foreign currency forward sales contracts. At Dec. 31, 2002, the corporation had hedged approximately 94 per cent (2001 - 98 per cent) of its currency rate exposures on a pre-tax basis.

Translation gains and losses related to the carrying value of the corporation's foreign operations are deferred and included in the cumulative translation account in shareholders' equity. At Dec. 31, 2002, the balance in this account was a loss of $18.8 million compared to a $19.5 million loss at the end of 2001.

CREDIT RISK 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 sets strict credit limits for each counterparty and the mix of counterparties based on their credit ratings and halts trading activities with a counterparty if the limits are exceeded.

TransAlta is exposed to minimal credit risk for Alberta Generation PPAs because under the terms of these arrangements all receivables are guaranteed by the Alberta government.

A summary of the corporation's credit risk exposure for its trading operations at Dec. 31, 2002, including asset-backed trading is provided below:

Rating	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10%	Net Exposure of Counterparties Greater than 10%
Investment grade	$ 111.4	$ -	$ 111.4	$ -	$ -
Non-investment grade	14.9	7.4	7.5	-	-
No external rating, internally rated - investment grade	20.6	0.6	20.0	-	-
	$ 146.9	$ 8.0	$ 138.9	$ -	$ -

In the fourth quarter of 2000, TransAlta recorded a provision of US$28.8 million against US$58.0 million owing from the California Power Exchange Corp. and the California Independent System Operator. During 2001, approximately

US$5.0 million was collected. No change has been made to the provision due to the continuing uncertainty in California. Ultimate collection of the net receivable is expected.

The maximum credit exposure to any one customer, excluding the California Independent System Operator and California Power Exchange Corp. discussed above, and including the fair value of open trading positions, is $26.1 million receivable from Ontario Hydro.

LIQUIDITY RISK TransAlta is exposed to funding liquidity risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of hedging or proprietary trading. Funding liquidity risk relates to TransAlta's ability to meet margin and collateral requirements of these contracts. The terms and conditions of these contracts require TransAlta to provide collateral when the fair value of these contracts is both negative (out-of-the-money) and in excess of any credit limits granted by TransAlta's counterparties. The fair value of these contracts change due to changes in commodity prices and foreign exchange rates. These contracts are out-of-the-money in these circumstances: (i) for purchase agreements, when forward commodity prices are less than contracted prices; and (ii) for sales agreements, when forward commodity prices exceed contracted prices. Downgrades in TransAlta's creditworthiness may decrease the credit limits granted by TransAlta's counterparties.

In the absence of any credit limits granted by TransAlta's counterparties, TransAlta's maximum collateral requirements would have been $492.0 million at Dec. 31, 2002 if the corporation's credit ratings were below investment grade. Collateral available was approximately $1 billion.

INTEREST RATE EXPOSURE The corporation has exposure to movements in interest rates and manages this exposure by maintaining a limit on the amount of debt subject to floating interest rates. At Dec. 31, 2002, approximately 25 per cent of the corporation's total debt portfolio was subject to movements in floating interest rates through a combination of floating rate debt and interest rate swaps.

OPERATIONAL RISK The corporation's plants have exposure to operational risks such as fatigue cracks in boilers, corrosion in boiler tubing, turbine failures and other issues that can lead to outages. A comprehensive plant maintenance program and regular turnarounds reduce this exposure. Force majeure clauses in the PPAs and insurance further mitigate this exposure.

Approximately 54 per cent of the corporation's labour force is covered under collective bargaining agreements. The agreements of approximately 56 per cent of this unionized labour force are being negotiated during 2003. Management does not anticipate any significant issues in the renegotiations of these agreements.

The construction and development of generating facilities and acquisition activities are subject to various environmental, engineering, and construction risks relating to cost-overruns, delays and performance. The corporation attempts to minimize these risks by performing detailed analysis of project economics prior to construction or acquisition and by securing favourable power sales agreements.

The corporation's fuel supply and fuel costs for gas-fired plants are managed with short-, medium- and long-term gas supply contracts, gas hedging transactions, and contractual agreements that provide for the flow-through of gas costs. The corporation believes adequate supplies of natural gas at reasonable prices will be available for plants when existing supply contracts expire.

ENVIRONMENTAL, HEALTH AND SAFETY RISK TransAlta's approach is to continually improve the management of operational risks in the areas of environment, health and safety while developing mechanisms to manage future risks. These programs are integrated into the operations and management systems of the company and are designed to mitigate the potential competitive risks to its fossil-fuelled generation plants from future changes in public policy. TransAlta's programs may include changes to environmental controls, regulatory regimes, taxes or charges to meet due diligence requirements and to enhance environmental performance through implementing systems and standards such as ISO 14001.

TransAlta's environmental strategy addresses the following key areas: reducing net emissions; participating in provincial, federal and international policy development; contributing to research and development; investing in renewable energy; and testing market-based approaches that deliver real environmental benefits, such as the trading of emission reduction credits.

TransAlta strives to maintain compliance with all environmental, health and safety regulations relating to its operations and facilities. If regulations were to change however, the operational and financial impact on all plants would need to be assessed. Outcomes may include, but are not limited to: increased compliance, maintenance or capital costs; plant impairment charges; or the decommissioning of certain facilities.

On Dec. 16, 2002, the Canadian government ratified the Kyoto Protocol. TransAlta is not able to estimate the full impact the ratification will have on its business, as the government has not yet established an implementation plan. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change of Law' provisions that provide an opportunity to recover compliance costs from the PPA customers. As a member of the Canadian Clean Power Coalition, TransAlta, along with its peers, is exploring other means to reduce greenhouse gas emissions. In 2002, as part of this strategy, TransAlta purchased the remaining interest in Vision Quest, a company that uses wind-based technology to generate electricity. TransAlta also made substantial investments in technology upgrades at the Centralia plant to significantly improve environmental performance by reducing emissions.

All TransAlta facilities undergo compliance and management system integrity audits on a cycle determined by facility performance, which on average, is once every three years. The Dow Jones Sustainability Indexes have again recognized TransAlta as one of the world's best utility companies in terms of environmental, health and safety performance, and TransAlta has also been recognized on the FTSE4 (Financial Times Stock Exchange) Good Global Index, a London-based sustainability index.

REGULATORY AND POLITICAL RISK Regulatory and political risks exist in the jurisdictions in which TransAlta operates. TransAlta manages these risks by working with regulators and other stakeholders to attempt to resolve issues as fairly and expeditiously as possible. Legislation was passed in Ontario in late 2002 capping retail market prices at $43 per MWh. Wholesale market prices have not been directly impacted by this decision; however, liquidity has decreased in the Ontario market as a result.

International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of the respective country. This risk is mitigated through the use of non-recourse financing and political risk insurance.

WEATHER-RELATED BUSINESS RISKS In early 1998, severe ice storms cut off electricity for weeks to millions of residents in Quebec and Ontario. The nature of the ice storm was particularly severe and widespread. This type of storm, although extremely unusual, is an ongoing risk for electric companies. This risk is mitigated through force majeure clauses in the Alberta PPAs and power sales contracts and access to multiple transmission lines.

CORPORATE STRUCTURE The corporation conducts a significant amount of business through subsidiaries and partnerships. The corporation's ability to meet and service debt obligations is dependent upon the results of operations of its subsidiaries and the payment of funds by such subsidiaries to the corporation in the form of distributions, loans, dividends or otherwise. In addition, TransAlta's subsidiaries may be subject to statutory or contractual restrictions which limit their ability to distribute cash to the ultimate shareholder, TransAlta Corporation.

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 property, plant and equipment, results of financing efforts, credit risk and counterparty risk.

INCOME TAXES The corporation's operations are complex, and the computation of the 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. Management believes that it has adequately provided for income taxes based on all information currently available.

LEGAL CONTINGENCIES The corporation, through generation and marketing activities, is occasionally named as a defendant in various claims and legal action. The nature of these claims is usually related to personal injury, environmental issues and pricing. Exposure to these claims is mitigated through levels of insurance coverage considered appropriate by management. Except as disclosed in Note 24 to the consolidated financial statements, the corporation does not expect the outcome of the claims or potential claims to have a materially adverse effect on the corporation as a whole.

OTHER CONTINGENCIES The corporation maintains a level of insurance coverage deemed appropriate by management and for matters for which insurance coverage can be maintained. There were no significant changes to TransAlta's insurance coverage during 2002 except for the discontinuance of coverage for terrorist acts, which is no longer available from insurance providers.

SENSITIVITY ANALYSIS The following table shows the effect on net earnings and cash flows of changes in certain key variables. The analysis is based on business conditions and production volumes in 2002. Each separate item in the sensitivity assumes the others 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.

		Approximate impact	
Factor	Change	Cash flow	Earnings (after-tax)
Electricity price	$1.00/MWh	$ 2.9	$ 2.9
Natural gas price	$0.1/mmBtu	(0.7)	(0.7)
Availability	1%	8.9	8.9
Production	1%	7.7	7.7
Exchange rate (US$ per Cdn$)	US$0.01	-	-
Interest rate	1%	2.5	2.5

The impact of a $1.00 per MWh change in electricity prices has minimal impact on cash flow and after-tax earnings as approximately 90 per cent of output is fixed under long-term contracts. A change in natural gas prices also has minimal impact as 62 per cent of gas costs have been contractually fixed or flow through to customers under terms of agreements.

A one per cent change in availability has a greater impact on cash flow and after-tax earnings than a one per cent change in production because a change in availability impacts both production levels attainable and capacity payments received for achieving specific availability levels as defined in PPAs. A change in production affects actual output levels and corresponding revenues.

TransAlta's hedging strategies have minimized the impact of changes in exchange rates and interest rates as the corporation's net investments in foreign operations have been hedged and interest rates on approximately 75 per cent of TransAlta's debt have been fixed.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The selection and application of accounting policies is an important process that has developed as TransAlta's 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 corporation's business. Every effort is made to comply with all applicable rules on or before the effective date, and TransAlta believes 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, the corporation's best judgment is used to adopt a policy for accounting for these situations. This is accomplished by analogizing to similar situations and the accounting guidelines governing them, and consultation with the corporation's independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involve s 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 the corporation's financial statements.

TransAlta's 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, property, plant and equipment, goodwill, income taxes and employee future benefits (Notes 1(D), (G), (H), (L) and (M), respectively). Each policy involves a number of estimates and assumptions to be made by management about matters that are highly uncertain at the time the estimate is made. Different estimates, with respect to key variables the corporation used for the calculations, or changes to estimates could potentially have a material impact on TransAlta's financial position or results of operations. These critical accounting estimates are described below.

Management has discussed the development and selection of these critical accounting estimates with the A&E committee and the corporation's independent auditors. The A&E committee has reviewed and approved the corporation's 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 expected to have a similar opposite impact. Each separate item in the sensitivity assumes all other factors remain constant.

Revenue recognition

The majority of the corporation's revenues are derived from the sale of physical power and from Energy Marketing and risk management 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, as specified by contractual terms. Revenues from non-contracted capacity are comprised of energy payments for each MWh produced at market prices, and is recognized upon delivery or output to the customer.

Trading activities use derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. Under Canadian GAAP, 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 price risk management assets and liabilities. Non-derivative contracts entered into subsequent to the rescission of EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, are accounted for using the accrual method. Prior to the rescission, mark-to-model accounting was used for non-derivative contracts.

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. Some derivatives have quoted market prices from the New York Mercantile Exchange , or over-the-counter quotes are 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, other than transmission rights acquired to sell production from TransAlta plants, and physical transmission rights used by the Energy Marketing segment. Changes in fair value of derivatives subsequent to inception are recorded on the balance sheet 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 the corporation 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 the corporation's position in an orderly manner over a reasonable period of time under present market conditions and operational risk. TransAlta validates its mark-to-model results by comparing 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 the control of the corporation, and may be material.

Key variables used in the models are uncertain. The estimated value of these contracts at Dec. 31, 2002 using mark-to-model methodology was $1.6 million. Sensitivities of the valuation, which would have been recorded in earnings in the current period, are as follows:

Assumption	Change in assumption	Impact on pre-tax earnings
Change in volatility	1%	$ -
Change in commodity price	1%	0.1

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

Valuation of property, plant and equipment

In the fourth quarter of 2002, TransAlta adopted the CICA's new impairment standard, which harmonizes Canadian standards with the U.S. standard. These standards require the corporation to determine whether the net carrying amount of property, plant and equipment (PP&E) is recoverable from future cash flows. Factors which could indicate that an impairment exists include significant underperformance relative to historical or projected future operating results, significant changes in the manner or use of the assets, the strategy for the corporation's 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 TransAlta is not the operator of the project. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The corporation's businesses, the market and business environment are 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, is less than the carrying amount of the asset, an asset impairment must be recognized in the 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.

PP&E makes up 81 per cent of the corporation's assets, of which 96 per cent relate to the Generation segment. Plants are reviewed for impairment when conditions of impairment exist. Unit three of the Wabamun plant experienced an unplanned outage in the fourth quarter of 2002. The significant amount of capital required to return the unit to service and the pending expiration of the PPA indicated that an impairment may exist, therefore this plant was reviewed for impairment. The corporation determined that the undiscounted sum of the expected future cash flows from the Wabamun plant was less than the carrying value of the asset, therefore an impairment charge of $110.0 million pre-tax was recognized in the fourth quarter of 2002. The Big Hanaford and Sarnia plants are primarily merchant plants. As spark spreads have declined significantly in each of the plants' respective markets, an impairment test was performed for each of the plants. For both plants, the corporation determined that the undiscounted sum of the expected future cash flows exceeded the carrying values, so no impairment charges were recognized. No other plants showed indications of impairment.

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, the corporation used estimates based on 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.

Estimates of future cash flows for the Wabamun plant reflect sustained historical availability and production levels throughout 2003, except for unit three, which was decommissioned in the fourth quarter of 2002. In 2004, units one and two are assumed to be retired while unit four is assumed to operate until 2010 at availability levels reflective of historical capability and age-related outage factors. Revenues between 2004 and 2010 assume market-based pricing. Fuel and plant operating costs reflect operating levels. Sensitivities for the major assumptions are as follows:

Assumption	Change in assumption (%)	Impact on impairment charge (pre-tax)

Electricity prices	10	$ 19.0
Fuel prices	10	$ 4.0
Volumes produced	3	$ 12.0
Discount rate	3	$ 6.0

Undiscounted future cash flows for the Sarnia and Big Hanaford plants are calculated based on the corporation's forward view of spark spreads at Dec. 31, 2002, which are expected to compress in the near term, and to recover in the medium to long term. Because the plants only operate when spark spreads are above certain levels to recover variable costs, fluctuations in electricity prices and natural gas prices will also affect production levels. Therefore, the calculation of sensitivities of changes in these variables, with all other variables remaining constant, will not produce a meaningful result.

At Dec. 31, 2002, the carrying values of the Sarnia and Big Hanaford plants were $473.3 million and $307.7 million, respectively.

Useful life of Property, Plant and Equipment

A significant amount of the corporation's assets are PP&E related to the corporation's generating and mining activities (79 per cent). PP&E is depreciated over its estimated useful life. The 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 $256.1 million in 2002, of which $37.1 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 $13.3 million in depreciation and amortization expense.

Valuation of goodwill

The corporation evaluates 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 the impairment loss.

Goodwill was recorded on the acquisition of MEGA, completed in 2001, and on the acquisition of Vision Quest, completed in 2002 (Note 5). At Dec. 31, 2002, this goodwill had a total carrying value of $56.5 million. Additional goodwill will be recorded as a result of the January 2003 acquisition of CE Gen (Note 26).

The corporation reviewed the $29.3 million of goodwill related to the MEGA acquisition on initial adoption of the new goodwill standard on Jan. 1, 2002, and in the fourth quarter of 2002 in connection with the corporation's annual impairment test. To test for impairment, the fair value of the reporting unit to which the goodwill relates, the Energy Marketing segment, was compared to the carrying value of the reporting unit. The corporation determined that the fair value of the Energy Marketing segment, based on historical cash flows and estimates of future cash flows, exceeded its carrying value, therefore no impairment charge was recorded upon initial adoption or when the annual impairment test was performed.

The fair value determination of the Energy Marketing segment is susceptible to change from period to period as management is required to make assumptions about future cash flows, trading volumes, margins and operating costs. Future cash flow estimates for the Energy Marketing segment assume that future margins in the Energy Marketing segment remain consistent with 2002, therefore there is no impairment issue. Had the assumption been made that future margins decline by 10 per cent from current levels, there would not have been any impairment of goodwill. To the extent goodwill is impaired, the impairment charge would impact earnings in the period of the charge, but would not have a material impact on liquidity and capital resources as the corporation would be within its debt covenants.

Goodwill will be tested annually for impairment in the fourth quarter of each year, or earlier if indicators of impairment exist.

Income taxes

In accordance with Canadian GAAP, the corporation uses the liability method of accounting for future income taxes and provides future income taxes for all significant income tax temporary differences. The Canadian standard is substantially the same as the U.S. standard.

Preparation of the consolidated financial statements requires an estimate of income taxes in each of the jurisdictions in which the corporation operates. The process involves an estimate of the corporation's actual 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 which are included in the corporation's consolidated balance sheet.

An assessment must also be made to determine the likelihood that the corporation's 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 $90.9 million have been recorded on the consolidated balance sheet at Dec. 31, 2002. This is comprised primarily of unrealized losses on electricity trading contracts, future site restoration costs and net operating and capital loss carryforwards. The corporation believes 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 $389.0 million have been recorded on the consolidated balance sheet at Dec. 31, 2002. The liability is comprised primarily of unrealized gains on electricity trading contracts and income tax deductions in excess of related depreciation of PP&E.

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

The corporation's tax filings are subject to audit by taxation authorities. The outcome of some audits may increase the tax liability of the corporation, although management believes that it has 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

As explained in Note 19 to the consolidated financial statements, the corporation provides post-retirement benefits to employees. The cost of providing these benefits is dependent upon many factors which result from actual plan experience and assumptions of future experience.

Pension costs are impacted by actual 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. In addition, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions:

Actuarial assumption	Change in assumption (%)	Impact on projected benefit obligation	Impact on pension cost reported in earnings
Discount rate	1	$ 36.6	$ 0.6
Rate of return on plan assets	1	-	3.7

The discount rate used represents high-quality fixed income securities currently available and expected to be available during the period to maturity of the pension benefits. The corporation believes it uses a conservative approach in setting the discount rate and does not expect to make any changes to the rate in 2003.

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 market value of the corporation's plan assets has been affected by recent declines in equity markets. For the year ended Dec. 31, 2002, the plan assets had a negative return of $6.7 million compared to earnings of $9.9 million in 2001 and $48.9 million in 2000. The 2002 actuarial valuation used the same rate of return on plan assets (7.0 to 8.5 per cent) as was used in 2001 and 2000.

As a result of the corporation's plan asset return experience for its U.S. registered pension plan, at Dec. 31, 2002, the corporation was required under U.S. GAAP to recognize an additional minimum liability (Note 27). The liability was recorded as a reduction in common equity through a charge to other comprehensive income (OCI), and did not affect net income for 2002. The charge to OCI will be restored through common equity in future periods to the extent the fair value of the trust assets exceeds the accumulated benefit obligation.

The amount of the additional pension liability to be recognized at Dec. 31, 2002 for U.S. GAAP depended on a number of factors, including the discount rate and asset returns experienced, contributions made by the corporation and any resulting change in management's assumptions. In addition, pension cost and cash funding requirements could increase in future years without a substantial recovery in the equity markets.

EMPLOYEE SHARE OWNERSHIP

TransAlta employs a variety of stock-based compensation plans to align employee and corporate objectives. In 2001, the corporation expanded enrolment in the corporation's common share option program to include all Canadian and U.S. employees of the corporation. At Dec. 31, 2002, 3.2 million options to purchase the corporation's common stock were outstanding with 0.8 million exercisable at the reporting date.

Under the terms of the Performance Share Ownership Plan (PSOP), certain employees receive awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent plus dividends thereon based upon the performance of the corporation relative to a selected group of publicly traded companies. On Dec. 31, 2001, the plan was modified so that after three years, once 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. The first PSOP maturity occurred in 2000 with 120,101 common shares issued at $14.15 per share. In 2001, 83,077 common shares were issued at $22.00 per share. In 2002, 84,578 common shares were issued at $21.60 per share. At Dec. 31, 2002, there were 1.4 million PSOP awards outstanding.

Under the terms of the Employee Share Purchase Plan, the corporation will extend an interest-free loan to employees of up to 30 per cent of the employee's base salary for the purchase of common shares of the corporation 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, 2002, 0.3 million shares had been purchased by employees under this program.

EMPLOYEE FUTURE BENEFITS

TransAlta has 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 and in Canada, there is a supplemental defined benefit plan for certain employees. 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, 2002. As the Canadian registered plan has a funded surplus, there is no requirement for the corporation to fund the registered plan in 2003.

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 April 30, 2002.

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 $34.5 million to secure the obligations under the supplemental plan.

SELECTED QUARTERLY FINANCIAL INFORMATION

(Unaudited; in millions of Canadian dollars except per share amounts)

2002 Quarters	First	Second	Third	Fourth	Annual
Total revenues	$ 419.7	$ 336.3	$ 450.3	$ 517.6	$ 1,723.9
Earnings (loss) from continuing operations	45.7	18.5	73.4	(59.6)	78.0
Net earnings (loss) applicable to common shareholders	51.4	124.9	67.9	(54.3)	189.9
Basic earnings (loss) per common share:					
Continuing operations	0.24	0.08	0.40	(0.38)	0.34
Net earnings	0.30	0.74	0.40	(0.32)	1.12
Diluted earnings (loss) per common share:					
Continuing operations	0.22	0.07	0.40	(0.38)	0.34
Net earnings	0.28	0.73	0.40	(0.32)	1.12

2001 Quarters	First	Second	Third	Fourth	Annual
Total revenues	$ 706.5	$ 605.2	$ 573.3	$ 434.4	$ 2,319.4
Earnings from continuing operations	59.0	50.2	36.7	36.7	182.6
Net earnings applicable to common shareholders	67.6	59.1	41.4	46.5	214.6
Basic earnings (loss) per common share:					
Continuing operations	0.33	0.28	0.20	0.19	1.00
Net earnings	0.40	0.35	0.25	0.27	1.27
Diluted earnings (loss) per common share:					
Continuing operations	0.32	0.27	0.20	0.19	0.98
Net earnings	0.39	0.34	0.25	0.27	1.25

Consolidated Financial Statements

Years ended Dec. 31, 2002, 2001 and 2000

MANAGEMENT'S RESPONSIBILITY

TransAlta's management is responsible for presentation and preparation of the annual consolidated financial statements, management's discussion and analysis (MD&A) and all other information in this annual report.

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and the requirements of the Securities and Exchange Commission (SEC) in the U.S., as applicable.

The MD&A has been prepared in accordance with the requirements of securities regulators including National Instrument 44-101 of the Canadian Securities Administrators as well as Item 303 of Regulation S-K of the Securities Exchange Act, and their related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgements and estimates of the expected effects of current events and transactions with appropriate consideration for materiality. In addition, in preparing financial information, the corporation must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the estimated impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from management's present assessment of this information because future events and circumstances may not occur as expected.

The financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To meet its responsibility for reliable and accurate financial statements, management has established systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization. These systems are monitored by management and by internal auditors. In addition, the internal auditors perform appropriate tests and related audit procedures.

The consolidated financial statements have been examined by Ernst & Young LLP, independent chartered accountants. The external auditors' responsibility is to express a professional opinion on the fairness of management's consolidated financial statements. The auditors' report outlines the scope of their examination and sets forth their opinion.

The Audit and Environment (A&E) Committee of the Board of Directors is comprised of independent directors. The A&E Committee meets regularly with management, the internal auditors and the external auditors to satisfy itself that each is properly discharging its responsibilities, and to review the consolidated financial statements and MD&A. The A&E Committee reports its findings to the Board of Directors for consideration when approving the consolidated financial statements for issuance to the shareholders. The A&E Committee also recommends, for review by the Board of Directors and approval of shareholders, the appointment of the external auditors. The internal and external auditors have full and free access to the A&E Committee.

TransAlta's Chief Executive Officer and Chief Financial Officer have certified TransAlta Corporation's annual disclosure document filed with the SEC (Form 40-F) as required by the U.S. Sarbanes-Oxley Act.

Signed by

Stephen G. Snyder Ian A. Bourne
President & Chief Executive Officer Executive
Vice-President & Chief Financial Officer

March 15, 2003

AUDITORS' REPORT

TO THE SHAREHOLDERS OF TRANSALTA CORPORATION

We have audited the consolidated balance sheets of TransAlta Corporation as at December 31, 2002 and 2001 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2002. 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 generally accepted auditing standards in Canada and the United States. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the corporation as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles. We also report that, in our opinion, these principles have been applied, except for changes in method of accounting for impairment of long-lived assets, goodwill, foreign currency translation, hedging relationships, stock-based compensation and presentation of trading activities, as described in Note 1(R) to the consolidated financial statements, on a basis consistent with that of the preceding year.

Chartered Accountants
Calgary, Canada

February 1, 2003, except for Note 26, which is as of March 15, 2003

CONSOLIDATED STATEMENTS OF EARNINGS & RETAINED EARNINGS

Years ended Dec. 31 (in millions of Canadian dollars except per share amounts)	**2002**	2001	2000
Revenues	**$ 1,723.9**	$ 2,319.4	$ 1,671.1
Fuel and purchased power	**(703.6)**	(1,230.6)	(741.2)
Gross margin	**1,020.3**	1,088.8	929.9
Operating expenses			
Operations, maintenance and administration	**420.5**	392.2	349.9
Depreciation and amortization	**219.0**	191.2	191.3
Asset impairment and equipment cancellation charges (Note 8)	**152.5**	118.8	-
Taxes, other than income taxes	**27.4**	18.7	23.9
	819.4	720.9	565.1
Operating income	**200.9**	367.9	364.8
Other income (expense)	**0.1**	1.5	(1.1)
Foreign exchange gain	**1.2**	0.8	0.1
Net interest expense	**(82.7)**	(88.1)	(91.4)
Earnings from continuing operations before regulatory decisions, income taxes and non-controlling interests	**119.5**	282.1	272.4
Prior period regulatory decisions (Note 17)	**(3.3)**	11.0	44.1
Earnings from continuing operations before income taxes and non-controlling interests	**116.2**	293.1	316.5
Income tax expense (Note 18)	**18.1**	89.9	128.5
Non-controlling interests (Note 13)	**20.1**	20.6	41.6

Earnings from continuing operations		**78.0**		182.6		146.4
Earnings from discontinued operations (Note 3)		**12.8**		45.1		89.1
Gain on disposal of discontinued operations (Note 3)		**120.0**		-		266.8
Net earnings before extraordinary item		**210.8**		227.7		502.3
Extraordinary item (Note 4)		**-**		-		(209.7)
Net earnings		**210.8**		227.7		292.6
Preferred securities distributions, net of tax (Note 14)		**20.9**		13.1		12.8
Net earnings applicable to common shareholders	**$**	**189.9**	$	214.6	$	279.8
Common share dividends		**(169.0)**		(168.4)		(168.7)
Adjustment arising from normal course issuer bid (Note 15)		**(27.0)**		(34.8)		(7.5)
Retained earnings						
Opening balance		**838.3**		826.9		723.3
Closing balance	**$**	**832.2**	$	838.3	$	826.9
Weighted average common shares outstanding in the period		**169.6**		168.9		168.8
Basic earnings per share (Notes 14 and 15)						
Continuing operations	**$**	**0.34**	$	1.00	$	0.79
Earnings from discontinued operations (Note 3)		**0.07**		0.27		0.53
Net earnings from operations		**0.41**		1.27		1.32
Gain on disposal of discontinued operations (Note 3)		**0.71**		-		1.58
Extraordinary item (Note 4)		**-**		-		(1.24)
Net earnings	**$**	**1.12**	$	1.27	$	1.66
Diluted earnings per share (Notes 14 and 15)						
Earnings from continuing operations	**$**	**0.34**	$	0.98	$	0.77
Earnings from discontinued operations (Note 3)		**0.07**		0.27		0.53
Net earnings from operations		**0.41**		1.25		1.30
Gain on disposal of discontinued operations (Note 3)		**0.71**		-		1.58
Extraordinary item (Note 4)		**-**		-		(1.24)
Net earnings	**$**	**1.12**	$	1.25	$	1.64

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

Dec. 31		
(in millions of Canadian dollars)	**2002**	2001

Assets		
Current assets		
Cash and cash equivalents	**$ 143.3**	$ 62.0
Accounts receivable and other	**468.4**	625.3
Price risk management assets (Note 20)	**157.8**	137.6
Future income tax assets (Note 18)	**18.7**	16.9
Income taxes receivable	**111.5**	128.3
Materials and supplies at average cost	**112.7**	85.5
	1,012.4	1,055.6
Investments (Note 6)	**32.2**	37.3
Long-term receivables (Note 7)	**39.9**	221.4
Property, plant and equipment (Note 8)		
Cost	**8,124.9**	8,766.7
Accumulated depreciation	**(2,089.8)**	(2,671.9)
	6,035.1	6,094.8
Goodwill (Note 5)	**56.5**	29.3
Future income tax assets (Note 18)	**72.2**	15.6
Price risk management assets (Note 20)	**60.7**	71.3
Other assets (Note 9)	**110.6**	81.1
Total assets	**$ 7,419.6**	$ 7,606.4
Liabilities and shareholders' equity		
Current liabilities		
Short-term debt (Note 10)	**$ 290.0**	$ 537.2
Accounts payable and accrued liabilities	**472.2**	627.5
Price risk management liabilities (Note 20)	**173.8**	114.1
Future income tax liabilities (Note 18)	**17.1**	11.8
Dividends payable	**42.9**	42.8
Current portion of long-term debt (Note 11)	**355.4**	104.3
	1,351.4	1,437.7
Long-term debt (Note 11)	**2,351.2**	2,406.8
Deferred credits and other long-term liabilities (Note 12)	**540.2**	560.5
Future income tax liabilities (Note 18)	**371.9**	409.1
Price risk management liabilities (Note 20)	**50.6**	69.0
Non-controlling interests (Note 13)	**263.0**	281.0
Preferred securities (Note 14)	**451.7**	452.6
Common shareholders' equity		
Common shares (Note 15)	**1,226.2**	1,170.9
Retained earnings	**832.2**	838.3
Cumulative translation adjustment	**(18.8)**	(19.5)
	2,039.6	1,989.7

Total liabilities and shareholders' equity	**$ 7,419.6**	$ 7,606.4

Commitments and contingencies (Notes 23 and 24)

Subsequent events (Note 26)

On behalf of the board:

Signed by
John T. Ferguson
Director

Signed by
John S. Lane
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended Dec. 31

(in millions of Canadian dollars)	**2002**	2001	2000
Operating activities			
Net earnings	**$210.8**	$ 227.7	$ 292.6
Depreciation and amortization (Note 2)	**314.8**	312.3	353.0
Asset impairment and equipment cancellation charges (Note 8)	**152.5**	66.5	17.9
Non-controlling interests (Note 13)	**20.1**	20.6	44.6
Loss (gain) on sale of property, plant and equipment	**15.6**	(5.4)	(284.9)
Site restoration costs incurred	**(15.6)**	(14.8)	(4.2)
Future income taxes (recovery) (Note 18)	**(60.4)**	39.9	34.1
Unrealized gain from energy marketing activities (Note 20)	**(7.6)**	(6.3)	(24.0)
Gain on disposal of Transmission operation (Note 3)	**(120.0)**	-	-
Extraordinary item (Note 4)	**-**	-	209.7
Other non-cash items	**(23.1)**	9.5	(26.1)
	487.1	650.0	612.7
Change in non-cash operating working capital balances	**(49.4)**	65.6	(414.0)
Cash flow from operating activities	**437.7**	715.6	198.7
Investing activities			

Additions to property, plant and equipment	**(945.8)**	(1,246.5)	(795.0)
Acquisitions (Note 5)	**(40.1)**	(9.8)	(880.1)
Proceeds on sale of property, plant and equipment to TransAlta Cogeneration, L.P. (Note 5)	**-**	35.0	-
Disposals (Notes 3 and 5)	**818.0**	97.0	1,367.0
Proceeds on sale of property, plant and equipment	**2.3**	104.6	-
Long-term receivables	**165.3**	(46.3)	12.1
Long-term investments	**(6.1)**	-	(9.5)
Restricted investments	**-**	-	86.8
Deferred charges and other	**(29.8)**	(10.9)	13.7
Cash flow used in investing activities	**(36.2)**	(1,076.9)	(205.0)
Financing activities			
Net increase (decrease) in short-term debt	**(247.1)**	61.9	255.7
Issuance of long-term debt	**611.3**	789.9	330.8
Repayment of long-term debt	**(454.5)**	(292.7)	(204.6)
Redemption of preferred shares of a subsidiary	**-**	(122.1)	(146.8)
Issuance of common shares	**1.8**	14.1	4.6
Redemption of common shares	**(49.9)**	(44.4)	(23.9)
Distributions on preferred securities	**(34.9)**	(23.4)	(22.1)
Dividends on common shares	**(115.5)**	(149.6)	(158.4)
Net proceeds on issuance of preferred securities	**-**	169.4	-
Dividends to subsidiary's non-controlling preferred shareholders	**-**	(8.3)	(14.8)
Dividends to subsidiary's non-controlling common shareholders	**-**	-	(7.0)
Distributions to subsidiary's non-controlling limited partner	**(24.5)**	(26.3)	(21.0)
Deferred financing charges and other	**(7.6)**	0.2	4.8
Cash flow from (used in) financing activities	**(320.9)**	368.7	(2.7)
Cash flow from (used in) operating, investing and financing activities	**80.6**	7.4	(9.0)
Effect of translation on foreign currency cash	**0.7**	0.8	(12.5)
Increase (decrease) in cash and cash equivalents	**81.3**	8.2	(21.5)
Cash and cash equivalents, beginning of year	**62.0**	53.8	75.3
Cash and cash equivalents, end of year	**$143.3**	$ 62.0	$ 53.8
Cash taxes paid	**$123.1**	$ 41.5	$ 140.3
Cash interest paid	**$210.8**	$ 163.1	$ 173.2

See accompanying notes.

1 The change in non-cash operating working capital balances and cash flow from operating activities for the year ended December 31, 2000 includes the impact of increased deferral accounts receivable for the discontinued Alberta Distribution and Retail business operation until the date of disposal on August 31, 2000. The related proceeds from the disposal of these deferral accounts receivable, totalling $164.3 million are classified as cash provided by investing activities, of which $** million was received in 2002 (2000 - $24.2 million) (Note 3).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar 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). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP). The significant differences are described in Note 27.

The consolidated financial statements include the accounts of TransAlta Corporation (TransAlta or the corporation), all subsidiaries and the proportionate share of the accounts of jointly controlled corporations. TransAlta Utilities Corporation (TransAlta Utilities) and TransAlta Energy Corporation (TransAlta Energy) are the principal wholly owned operating subsidiaries.

TransAlta Utilities owns and operates electric generation in the province of Alberta. TransAlta Utilities also owned and operated transmission facilities and a distribution and retail (D&R) operation in Alberta. The Transmission operation was disposed of on April 29, 2002, and the D&R operation was disposed of on Aug. 31, 2000. TransAlta Energy is engaged in electric and thermal energy supply, energy services and energy marketing in Canada, the U.S., Mexico and Australia. TransAlta Energy also owned and operated an electricity generation and retail operation in New Zealand until the operations were disposed of on March 31, 2000 (Note 3).

B. MEASUREMENT UNCERTAINTY

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. 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 3, 20 and 24).

C. REGULATION

Commencing Jan. 1, 2001, all Alberta generating plants were deregulated and became subject to long-term power purchase arrangements (PPAs) for the remaining estimated life of each plant. The PPAs set a production requirement and availability target to be supplied by each plant or unit and the price at which each megawatt-hour (MWh) will be supplied to the customer. As the criteria for regulatory accounting were no longer met, Canadian GAAP for non-regulated businesses commenced on Dec. 31, 2000, in respect of the Alberta Generation operations. The discontinued Alberta D&R and Transmission operations followed regulatory accounting.

D. REVENUE RECOGNITION

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

Derivatives used in trading activities include physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. Under Canadian GAAP, these derivatives are accounted for using the fair value method of 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 price risk management assets and liabilities. Non-derivative contracts entered into subsequent to the rescission of EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities are accounted for using the accrual method. Prior to the rescission of EITF 98-10, non-derivative contracts were accounted for using mark-to-model accounting.

Some derivatives have quoted market prices or over-the-counter quotes are 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, requiring the use of internal valuation techniques or models (mark-to-model accounting).

Under U.S. GAAP, trading activities are accounted for in accordance with Statement 133, Accounting for Derivative Instruments and Hedging Activities, which is described in greater detail in Note 1(O).

E. DISCONTINUED OPERATIONS

The results of discontinued operations are presented 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.

F. MATERIALS AND SUPPLIES

The corporation's materials and supplies balance includes coal, replacement parts which will be used within one year and operating supplies. Coal is valued at the lower of cost and market. Replacement parts are valued using the specific identification method.

G. 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 costs include items such as materials, labour, interest and other appropriately allocated costs. As costs are expended for new construction, the entire amount is capitalized as PP&E on the consolidated balance sheets and is 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 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 amortized. These estimates are subject to revision in future periods based on new or additional information.

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

The corporation determines those debt instruments that best represent a reasonable measure of the cost of financing the assets under construction. These debt instruments and associated interest costs are included in the calculation of the weighted average interest rate used for capitalizing interest.

In the fourth quarter of 2002, TransAlta early adopted the new Canadian Institute of Chartered Accountants (CICA) impairment standard, which harmonizes the Canadian standard with the U.S. standard (Statement 144). These standards require the corporation to determine whether the net carrying amount of property, plant and equipment is recoverable from future undiscounted cash flows when indicators of impairment exist. Factors which 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, the strategy for the corporation's 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 where TransAlta is not the operator of the project. Events can occur in these situations that may not be known until a later date from their occurrence.

The corporation's businesses, the market and business environment are continually monitored, and judgements 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, 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 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 best estimated by calculating the present value of expected future cash flows related to the asset.

The application of the standard in the fourth quarter of 2002 resulted in the recognition of a pre-tax impairment loss of $110.0 million related to the Wabamun plant (Note 8).

H. GOODWILL

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Prior to Jan. 1, 2002, TransAlta amortized goodwill on a straight-line basis over the useful life of the acquired assets. Effective Jan. 1, 2002, the corporation prospectively adopted the new CICA standard for goodwill and other intangibles. The new standard requires business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. It also specifies that goodwill and certain intangibles are no longer 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 issue may arise earlier. 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.

The adoption of the new standard resulted in the reclassification of $29.3 million from acquired intangibles to goodwill, which is no longer subject to amortization under the new standard. There was no impairment of goodwill upon adoption of this standard. Net earnings and earnings per share for the years ended Dec. 31, 2001 and 2000 adjusted to exclude the amortization of the above amount are as follows:

Year ended Dec. 31	2001	2000
Reported net earnings applicable to common shareholders	$ 214.6	$ 279.8
Amortization of acquired intangibles	7.7	9.4

Adjusted net earnings applicable to common shareholders	$	222.3	$	289.2
Reported basic earnings per share	$	1.27	$	1.66
Amortization of acquired intangibles per share		0.05		0.06
Adjusted basic earnings per share	$	1.32	$	1.72
Reported diluted earnings per share	$	1.25	$	1.64
Amortization of acquired intangibles per share		0.05		0.06
Adjusted diluted earnings per share	$	1.30	$	1.70

I. FUTURE SITE RESTORATION COSTS

Future site restoration costs for coal plants are included in fuel and purchased power expense on a straight-line basis over the life of the asset. Estimated costs to reclaim mining properties are amortized primarily on a unit-of-production basis.

No provision for future site restoration for gas generation plants is recorded as management estimates the costs of restoration will be offset by the salvage values of the related plant.

The corporation does not provide for the removal costs associated with its hydroelectric generating structures as the costs are not reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be required for the foreseeable future and therefore, no amounts have been provided for site restoration costs for these facilities. Provisions are made for removal of hydro generating equipment.

J. 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 value of the 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.

Financing costs for the issuance of long-term debt, preferred shares and preferred securities are amortized to earnings on a straight-line basis over the term of the related issue.

Other costs capitalized on the balance sheet include business development costs, which includes external, direct and incremental costs which are necessary for completion of a potential acquisition or construction project. Business development 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 in the current period.

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), the carry forward of unused tax losses and income tax reductions. 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 income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered 'more likely than not', a valuation allowance is provided.

Under U.S. GAAP, a difference arises as a result of the requirement for income tax balances to reflect currently legislated tax rates rather than substantively enacted tax rates.

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. For the purpose of calculating the expected return on plan assets, those assets are valued at market value. The discount rate used to calculate the interest cost on the accrued benefit obligation is the long-term market rate at the balance sheet date. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment (EARSL). 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 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 self-sustaining foreign operations are translated using the current rate method. Translation gains and losses are deferred and included in the cumulative translation adjustment (CTA) account in shareholders' equity.

The CICA amended its standard on foreign currency translation effective Jan. 1, 2002. The changes require that translation gains and losses arising on long-term foreign currency denominated monetary items be included in income in the current period. Previously, these gains and losses were to be amortized over the life of the related item. As TransAlta designates long-term foreign currency denominated items as hedges of net investments in foreign operations, all gains and losses arising on the translation of these items are deferred and included in CTA, a separate component of shareholders' equity, therefore this amendment has no impact on TransAlta.

Transactions denominated in foreign currencies are translated at the exchange rate on the transaction date. Foreign currency denominated monetary and non-monetary assets and liabilities are translated at exchange rates in effect on the balance sheet date. The resulting exchange gains and losses on these items are included in net earnings. Gains and losses arising on translation of long-term debt designated as a hedge of self-sustaining foreign operations are deferred and included in CTA in shareholders' equity on a net of tax basis.

O. DERIVATIVES AND FINANCIAL INSTRUMENTS

In November 2001, the CICA released an accounting guideline on hedging relationships, which specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges. The guideline also identifies situations where hedge accounting is to be discontinued. The guideline is effective for years beginning on or after July 1, 2003. TransAlta has early adopted the guideline effective Jan. 1, 2002 and met the criteria for all hedging relationships with the exception of written swaptions, which are ineffective under the guideline. Hedge accounting was discontinued for the written swaptions in accordance with the guideline. The impact on earnings for the year ended Dec. 31, 2002 was a decrease of $2.0 million after-tax.

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

Physical and financial swaps, forward sales contracts, futures contracts and options are used to hedge the corporation's exposure to fluctuations in electricity and natural gas prices. Under Canadian GAAP, if hedging criteria are met (described below), gains and losses on these derivatives are deferred and recognized in earnings in the same period and financial statement caption as the hedged exposure (settlement accounting). The derivatives are not recorded on the balance sheet.

Cross-currency interest rate swaps, foreign currency forward sales contracts and foreign currency long-term debt 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. Under Canadian GAAP, gains and losses on the principal component of the cross-currency interest rate swaps as well as gains and losses on the forward sales contracts and foreign currency long-term debt are deferred and included in CTA, a separate component of shareholders' equity, on a net of tax basis. The principal component of the cross-currency interest rate swaps is deferred and recorded in other assets (Note 9) or deferred credits and other long-term liabilities (Note 12) as appropriate. The forward sales contracts are not recognized on the balance sheet in accordance with Canadian GAAP.

Foreign exchange forward contracts are used to hedge the foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies. Under Canadian GAAP, if hedge criteria are met, these derivatives are not recognized on the balance sheet. Upon settlement of the derivative, any gain or loss on the forward contracts are deferred and included in other assets (Note 9) or deferred credits and other long-term liabilities (Note 12), and is included in the cost of the asset when the asset is purchased and depreciated over the asset's estimated useful life (settlement accounting).

Interest rate swaps are used to manage the impact of fluctuating interest rates on existing debt and forward starting interest rate swaps, spread locks and treasury locks are used to hedge the interest payments of anticipated future debt issuances. These instruments are not recognized on the balance sheet under Canadian GAAP. 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 (settlement accounting).

Under U.S. GAAP, trading and non-trading activities are accounted for in accordance with Statement 133, which requires that derivative instruments be recorded in the consolidated balance sheets at fair value as either assets or liabilities, and that changes in fair value be recognized currently in earnings, unless specific hedge accounting criteria are met. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized currently in earnings. If the derivative is designated as a cash flow hedge, the changes in the fair value of the derivative are recorded in other comprehensive income, and the gains and losses related to these derivatives are recognized in earnings in the same period as the settlement of the underlying hedged transaction. Any ineffectiveness relating to these hedges is recognized currently in earnings. The assets and liabilities related to derivative instruments for which hedge accounting criteria are met are reflected as derivative hedging instruments in the consolidated balance sheets. Many of the corporation's electricity sales and fuel supply agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment. This exemption is available for the electricity industry as electricity cannot be stored in significant quantities and generators may be required to maintain sufficient capacity to meet customer demands. This exemption is also available for some physically settled commodity contracts if certain criteria are met. Non-derivatives used in trading activities are accounted for using the accrual method under U.S. GAAP.

To be accounted for as a hedge under both Canadian and U.S. GAAP, 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 flows is achieved if the derivative's cash flows substantially offset the cash flows of the hedged item and the timing of the cash flows is 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. In a highly effective hedging relationship, any hedge ineffectiveness 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, and is not replaced as part of the corporation's hedging strategy, 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, and the hedged item is no longer probable of occurring, any previously deferred amounts 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.

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 16. On Jan. 1, 2002, the corporation retroactively adopted the new CICA standard for stock-based compensation. The new standard requires that stock-based payments to non-employees, direct awards of stock and awards that call for settlement in cash or other assets be accounted for using the fair value method of accounting. The fair value method is encouraged for other stock-based compensation plans, but other methods of accounting, such as the intrinsic value method, are permitted. Under the fair value method, compensation expense is measured at the grant date and recognized over the service period. Under the intrinsic value method, compensation expense is determined as the difference between the market price of the underlying stock and the exercise price of the equity instrument granted. If the intrinsic value method is used, disclosure is made of earnings and per share amounts as if the fair value method had been used. The corporation has elected to use the intrinsic value method of accounting for its fixed stock option plans and its performance stock option plan. Accordingly, no compensation cost has been recognized for these plans. Had the fair value method been used, the impact would be as disclosed in Note 16(E). Effective Jan. 1, 2003, the corporation will prospectively adopt the fair value method of accounting for stock-based compensation, and will therefore recognize stock-based compensation as an expense in respect of its stock option plans.

Stock grants under PSOP are accrued in corporate operations, maintenance and administration 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 a selected group of publicly traded companies. Compensation expense under the phantom stock option plan is recognized in operations, maintenance and administration expense 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. EARNINGS PER SHARE

Effective Jan. 1, 2001, the corporation retroactively adopted the CICA standard requiring the use of the treasury stock method rather than the imputed earnings method in calculating diluted earnings per share (EPS). The impact of this change on current and prior period diluted earnings per share was not material. Prior period amounts have been restated to comply with the new standard. Supplemental diluted earnings per share information disclosed in Note 14 is calculated assuming settlement of the equity component of the preferred securities by issuance of the corporation's common shares.

R. CHANGES IN ACCOUNTING STANDARDS

The CICA amended its standard on the recognition, measurement, and disclosure of the impairment of long-lived assets. This standard is effective April 1, 2003, however TransAlta adopted the standard in the fourth quarter of 2002. The impact of the adoption is described in Note 1(G).

Effective Jan. 1, 2002, the corporation prospectively adopted the new CICA standard for goodwill and other intangibles. The impact of adoption of this standard is described in Note 1(H).

The CICA amended its standard on foreign currency translation effective Jan. 1, 2002. The effect of this change is described in Note 1(N).

In November 2001, the CICA released an accounting guideline on hedging relationship, which was adopted by TransAlta on Jan. 1, 2002. The impact of adoption is described in Note 1(O).

On Jan. 1, 2002, the corporation retroactively adopted the new CICA standard for stock-based compensation. The impact of adoption of this standard is described in Note 1(P).

In the third quarter of 2002, in response to changes in accounting standards in the U.S. with respect to energy trading activities, the corporation adopted a policy that all gains and losses on energy trading contracts be shown net in the statements of earnings. Consistent with these recommendations, the corporation has chosen to disclose the gross transaction volumes for those energy contracts that are physically settled.

The CICA established a new standard on the disposal of long-lived assets and discontinued operations effective May 1, 2003. The standard requires that a long-lived asset to be disposed of other than by sale shall continue to be classified as held and used until it is disposed of. Certain criteria must be met before a long-lived asset can be classified as held for sale. The standard also defines discontinued operations more broadly than previously and prohibits the inclusion of future operating losses in a loss recognized upon classification of a long-lived asset as held for sale. TransAlta will early adopt this standard effective Jan. 1, 2003.

The CICA has proposed a new standard for asset retirement obligations, effective Jan. 1, 2004, with earlier adoption encouraged. The new rules require the recognition of an asset retirement obligation at fair value when incurred, unless the fair value cannot be reasonably determined. When the liability is recognized, a corresponding asset retirement cost is added to the carrying amount of the related asset, and is depreciated over the estimated useful life of the related asset. Accretion of the liability due to the passage of time is an operating expense. The expected impact of the adoption of the standard has not been finalized.

2. Segment disclosures

A. DESCRIPTION OF REPORTABLE SEGMENTS

The corporation has two reportable segments, each supported by the corporate group: Generation and Energy Marketing. A third business segment, Independent Power Projects (IPP), was combined with the Generation segment effective Jan. 1, 2002, following changes to TransAlta's operational structure. A fourth business segment, Transmission, was reclassified as a discontinued operation following the announcement of the agreement to dispose of the segment on July 4, 2001. The operation was sold on April 29, 2002 (Note 3). The Alberta Distribution and Retail operation (D&R) and the New Zealand operations were reclassified as discontinued operations on Dec. 31, 1999. The Alberta D&R operation was sold on Aug. 31, 2000 and the New Zealand operation was sold on March 31, 2000. Prior period amounts have been reclassified to reflect these changes. The business segments are strategic business units that offer different products and services, and each is managed separately. The corporate group includes investments in renewables and provides finance, treasury, legal, human resources and other administrative support to the business segments. Corporate overheads are allocated to the business segments to the extent they are not directly attributable to discontinued operations.

Each business segment assumes responsibility for its operating results measured as earnings before interest, taxes and non-controlling interests (EBIT). EBIT should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with Canadian GAAP as an indicator of the corporation's performance or liquidity. TransAlta's EBIT is not necessarily comparable to a similarly titled measure of another company. EBIT can be determined from the consolidated statements of earnings by deducting earnings and gains from discontinued operations, other income (expense) and foreign exchange gains (losses) and adding net interest expense, prior period regulatory decisions, income taxes and non-controlling interests to net earnings applicable to common shareholders.

The Generation segment owns coal, gas and hydro power plants in the Canada, the U.S., Mexico and Australia, and generates its revenue from the sale of electricity, steam and ancillary services. Generation expenses include Energy Marketing's intersegment charge for energy marketing and financial risk management services in the amount of $8.7 million (2001 - $7.4 million; 2000 - $7.1 million).

The Energy Marketing segment derives revenue from the wholesale trading of electricity and other energy-related commodities and physical and financial contracts in Canada and the U.S. Expenses are net of intersegment charges to the Generation segment for the provision of energy marketing and financial risk management services as stated in the previous paragraph and to the discontinued Alberta D&R operation in the amount of $nil (2001 - $nil; 2000 - $1.0 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 which approximates market rates. Segment revenues are net of intersegment transactions.

B. REPORTED SEGMENT PROFIT OR LOSS AND SEGMENT ASSETS

I. Earnings information

Year ended Dec. 31, 2002	**Generation**	**Energy Marketing**	**Corporate and other**	**Total**
Revenues	**$ 1,673.9**	**$ 3,703.8**	**$ 1.0**	**$ 5,378.7**
Trading purchases	**-**	**(3,654.8)**	**-**	**(3,654.8)**
Net segment revenues	**1,673.9**	**49.0**	**1.0**	**1,723.9**
Fuel and purchased power	**(703.6)**	**-**	**-**	**(703.6)**
Gross margin	**970.3**	**49.0**	**1.0**	**1,020.3**
Operations, maintenance and administration	**346.3**	**15.1**	**59.1**	**420.5**
Depreciation and amortization	**196.3**	**2.5**	**20.2**	**219.0**
	152.5	**-**	**-**	**152.5**

Asset impairment and equipment cancellation charges (Note 8)				
Taxes, other than income taxes	**27.3**	**0.1**	**-**	**27.4**
Prior period regulatory decisions (Note 17)	**3.3**	**-**	**-**	**3.3**
EBIT before corporate allocations	**244.6**	**31.3**	**(78.3)**	**197.6**
Corporate allocations	**(70.6)**	**(8.3)**	**78.9**	**-**
EBIT	**$ 174.0**	**$ 23.0**	**$ 0.6**	**197.6**
Other income				**0.1**
Foreign exchange gain				**1.2**
Net interest expense				**(82.7)**
Earnings from continuing operations before income taxes and non-controlling interests				**$ 116.2**

Year ended Dec. 31, 2001	**Generation**	**Energy Marketing**	**Corporate and other**	**Total**
Revenues	$ 2,158.4	$ 2,694.7	$ -	$ 4,853.1
Trading purchases	-	(2,533.7)	-	(2,533.7)
Net segment revenues	2,158.4	161.0	-	2,319.4
Fuel and purchased power	(1,230.6)	-	-	(1,230.6)
Gross margin	927.8	161.0	-	1,088.8
Operations, maintenance and administration	290.6	36.2	65.4	392.2
Depreciation and amortization	156.5	11.0	23.7	191.2
Asset impairment and equipment cancellation charge (Note 8)	118.8	-	-	118.8
Taxes, other than income taxes	18.7	-	-	18.7
Prior period regulatory decisions (Note 17)	(11.0)	-	-	(11.0)
EBIT before corporate allocations	354.2	113.8	(89.1)	378.9
Corporate allocations	(82.5)	(6.6)	89.1	-
EBIT	$ 271.7	$ 107.2	$ -	378.9
Other income				1.5
Foreign exchange gain				0.8
Net interest expense				(88.1)
Earnings from continuing operations before income taxes and non-controlling interests				$ 293.1

Year ended Dec. 31, 2000	**Generation**	**Energy Marketing**	**Corporate and other**	**Total**
Revenues	$ 1,593.3	$ 1,280.3	$ -	$ 2,873.6
Trading purchases	-	(1,202.5)	-	(1,202.5)

Net segment revenues	1,593.3	77.8	-	1,671.1
Fuel and purchased power	(741.2)	-	-	(741.2)
Gross margin	852.1	77.8	-	929.9
Operations, maintenance and administration	260.1	19.0	70.8	349.9
Depreciation and amortization	167.7	9.4	14.2	191.3
Taxes, other than income taxes	23.9	-	-	23.9
Prior period regulatory decisions (Note 17)	(44.1)	-	-	(44.1)
EBIT before corporate allocations	444.5	49.4	(85.0)	408.9
Corporate allocations	(77.9)	(7.1)	85.0	-
EBIT	$ 366.6	$ 42.3	$ -	408.9
Other expense				(1.1)
Foreign exchange gain				0.1
Net interest expense				(91.4)
Earnings from continuing operations before income taxes and non-controlling interests				$ 316.5

II. Selected balance sheet information

Dec. 31, 2002	**Generation**	**Energy Marketing**	**Corporate**	**Discontinued Operations**	**Total**
Goodwill	**$ -**	**$ 29.3**	**$ 27.2**	**$ -**	**$ 56.5**
Total segment assets	**$ 6,353.4**	**$ 344.6**	**$ 721.6**	**$ -**	**$7,419.6**
Dec. 31, 2001					
Goodwill	$ -	$ 29.3	$ -	$ -	$ 29.3
Total segment assets	$ 5,873.2	$ 413.3	$ 643.0	$ 676.9	$ 7,606.4

III. Selected cash flow information

Year ended Dec. 31, 2002	**Generation**	**Energy Marketing**	**Corporate**	**Discontinued Operations**	**Total**
Capital expenditures	**$ 909.1**	**$ 4.2**	**$ 10.7**	**$ 21.8**	**$ 945.8**
Year ended Dec. 31, 2001					
Capital expenditures	$ 1,147.6	$ 43.8	$ 15.1	$ 40.0	$ 1,246.5
Year ended Dec. 31, 2000					
Capital expenditures	$ 628.8	$ 27.2	$ 14.7	$ 124.3	$ 795.0

lV. Reconciliations

Depreciation and amortization (D&A) expense per statements of cash flows

Year ended Dec. 31	**2002**	2001	2000
D&A expense for reportable segments	**$ 219.0**	$ 191.2	$ 191.3
Discontinued operations	**15.6**	46.5	108.6
Mining equipment depreciation, included in fuel and purchased power	**37.1**	31.8	14.3
Site restoration accrual, included in fuel and purchased power	**38.9**	37.3	31.3
Other	**4.2**	5.5	7.5
	$ 314.8	$ 312.3	$ 353.0

C. GEOGRAPHIC INFORMATION

I. Revenues

Year ended Dec. 31	**2002**	2001	2000
Canada	**$ 1,207.6**	$ 2,069.2	$ 1,348.5
U.S.	**441.9**	188.7	267.7
Australia	**74.4**	61.5	54.9
	$ 1,723.9	$ 2,319.4	$ 1,671.1

Revenues are attributed to countries based on the location of customers. The Mexican plants have not yet commenced commercial operations and therefore no revenues have been generated.

II. Property, plant and equipment and goodwill

	PP&E		**Goodwill**	
	2002	2001	**2002**	2001
Canada	**$ 3,428.5**	$ 4,004.8	**$ 56.5**	$ 29.3
U.S.	**1,873.7**	1,665.3	**-**	-
Mexico	**545.8**	246.5	**-**	-
Australia	**187.1**	178.2	**-**	-
	$ 6,035.1	$ 6,094.8	**$ 56.5**	$ 29.3

3. Discontinued operations

A. TRANSMISSION

On April 29, 2002, TransAlta's Transmission operation was sold for proceeds of $820.7 million, of which $818.0 million has been collected. The proceeds excluded $31.7 million in accounts receivable, which were retained and subsequently collected, and $4.4 million in accounts payable. The disposal resulted in a gain on sale of $120.0 million ($0.71 per common share), net of income taxes of $36.2 million. The previously reported gain included a number of estimates, therefore the gain was adjusted in the fourth quarter of 2002 to reflect agreed working capital adjustments and actual amounts paid and received.

B. EDMONTON COMPOSTER

Effective Dec. 31, 2000, the corporation adopted a plan to divest its composter facility in Edmonton, Alberta, Canada, which commenced commercial operations in August 2000. In the fourth quarter of 2000, the corporation recorded a write-down of the carrying value of the assets of $17.9 million net of income tax recoveries of $13.8 million. On June 29, 2001, the facility was sold for cash proceeds of $97.0 million. No gain or loss resulted from the disposal.

C. ALBERTA DISTRIBUTION AND RETAIL (D&R) OPERATION

Effective Dec. 31, 1999, the corporation adopted a plan to divest its Alberta D&R operation. This operation was sold on Aug. 31, 2000 for proceeds of $857.3 million and an after-tax gain on disposal of $262.4 million ($1.55 per common share) net of income tax recoveries of $137.9 million. By Dec. 31, 2002, all proceeds had been received.

As per the terms of the disposition agreement, TransAlta will share the benefit or burden of future regulatory decisions affecting the Alberta D&R pre-disposition operation. No amount has been accrued in the consolidated financial statements as no amount was reasonably determinable at the reporting date.

D. NEW ZEALAND

Effective Dec. 31, 1999, the corporation adopted a plan to divest its New Zealand operations. On March 31, 2000, TransAlta sold its interest in its discontinued New Zealand operations for total proceeds of NZ$832.5 million (approximately Cdn$605 million) resulting in an after-tax gain on disposal of $22.3 million ($0.13 per common share) net of income taxes of $43.1 million.

E. STATEMENTS OF EARNINGS

Interest is allocated to discontinued operations based on the ratio of assets to be discontinued, net of directly attributable debt, to the total assets of the entity, net of debt that can be directly attributed to the discontinued operation or to particular continuing operations of the corporation. The statements of earnings amounts applicable to discontinued operations are as follows:

Year ended Dec. 31, 2002	**Transmis**
Revenues	**$**
Operating expenses	
Operating income	
Net interest expense	
Earnings before income taxes	
Income taxes	
Earnings before gain on disposal	
Gain on disposal (net of tax)	
Earnings from discontinued operations	**$**

Year ended Dec. 31, 2001	Transmission		Edmonton Composter		Total
Revenues	$	171.1	$	6.6	$
Operating expenses		84.6		5.4	
Operating income		86.5		1.2	
Net interest expense		(9.7)		-	
		76.8		1.2	

Earnings before income taxes									
Income taxes						(32.4)		(0.5)	
Earnings from discontinued operations [1]					$	44.4	$	0.7	$

[1] Transmission earnings include $23.4 million of earnings prior to the measurement date, net of taxes of $16.8 million.

Year ended Dec. 31, 2000	Transmission		Edmonton Composter		D&R		New Zealand		Total
Revenues	$	178.2	$	6.3	$	180.2	$	148.8	$
Operating expenses		83.6		4.1		103.3		125.8	
Operating income		94.6		2.2		76.9		23.0	
Net interest expense		(9.4)		(1.0)		(10.2)		(4.4)	
Earnings before income taxes and non-controlling interests		85.2		1.2		66.7		18.6	
Income taxes		(40.9)		(0.5)		(33.4)		(4.7)	
Non-controlling interests		-		-		-		(3.1)	
Earnings subsequent to (Transmission & Edmonton Composter - prior to) measurement date		44.3		0.7		33.3		10.8	
Gain on disposal (write-down of carrying value) (net of tax)		-		(17.9)		262.4		22.3	
Earnings from discontinued operations	$	44.3	$	(17.2)	$	295.7	$	33.1	$

F. BALANCE SHEETS

At Dec. 31, 2002, all of the corporation's discontinued operations had been sold. Balance sheet amounts at Dec. 31, 2001 were as follows:

		Transmission
Current assets	$	36.1
Property, plant and equipment		637.5
Other assets		3.3
Current liabilities		(15.5)
	$	661.4

4. Extraordinary item

In December 2000, the corporation discontinued regulatory accounting and commenced the application of Canadian GAAP for non-regulated entities for its Alberta Generation operations, consistent with deregulation of the electricity generation industry in Alberta beginning on Jan. 1, 2001.

As a result of the discontinuance of regulatory accounting, the corporation recorded an extraordinary non-cash after-tax charge of $209.7 million ($1.24 per common share) comprised of the following:

Write-off of regulatory accounts	$	2.5
Write-down of net carrying values of property, plant and equipment		17.3
Recognition of previously unrecognized future income tax liabilities		189.9
		$ 209.7

5. Acquisitions and disposals

A. ACQUISITIONS

On Dec. 6, 2002, the corporation completed a step acquisition of Vision Quest Windelectric Inc. (Vision Quest). The initial acquisitions between 2000 and 2002 resulted in 41 per cent ownership of Vision Quest for $13.5 million, accounted for using the equity method. Book values of the corporation's proportionate interest at the time of the initial acquisitions approximated fair values. The final step of the acquisition brought TransAlta's ownership to 100 per cent and TransAlta's total investment in Vision Quest to $68.8 million. The results of Vision Quest's operations have been included in the corporate segment of the consolidated financial statements since the date of acquisition. Vision Quest owns and operates 67 wind power turbine power plants with a total capacity of 44 MW with a further 50 per cent interest in the 75 MW McBride Lake joint venture currently under construction.

The aggregate purchase price includes the previous investments of $13.5 million, plus $21.3 million of cash and 745,791 common shares valued at $14.2 million. In addition, a loan of $19.8 million was previously advanced to Vision Quest. The value of the common shares issued was determined based on the average market price of TransAlta's common shares for the five days before and after the terms of the acquisition were agreed to and announced. 136,287 of the shares will be issued over the next three years.

The transaction has been accounted for using the purchase method. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Due to the timing of the purchase, it was impractical to complete the allocation process satisfactorily without causing undue delay in issuing the financial statements for the period in which the combination occurred. Therefore, the purchase price allocation was prepared based on the best allocations that could be made in the time available and, if necessary, the allocations in the purchase equation may be adjusted when the process is completed in the first quarter of 2003.

Net assets acquired at assigned values:		
Working capital, including cash of $8.2 million	$	6.5
Property, plant and equipment		70.1
Goodwill		27.2
Power purchase arrangement		2.5
Short-term debt		(32.2)
Future income tax liability		(4.7)
Interest rate swaps		(0.6)
Total	$	68.8

Consideration:		
Initial investments	$	13.5
Cash, including previous advances of $19.8 million		41.1
Common shares		14.2
Total	$	68.8

On Dec. 6, 2002, the corporation purchased the remaining 15 per cent interest in the Southern Cross Energy Partnership, located in Western Australia, for AUD$8.5 million (Cdn$7.2 million). At the time of acquisition, book values approximated fair values. The partnership is included in the Generation segment.

In May 2000, TransAlta purchased a power plant and the adjacent mining operations in Centralia, Washington, for cash consideration of US$582.7 million (Cdn$868.7 million). This acquisition was accounted for using the purchase method. This purchase included plant assets of $847.1 million, mine assets of $145.1 million, working capital of $65.7 million, estimated fair value of future site restoration liabilities of $168.8 million, future income tax liabilities of $5.8 million, accrued employee future liabilities of $7.5 million and other liabilities totalling $7.1 million. The plant is included in the Generation segment.

In June 2000, the corporation purchased a 50 per cent interest in Merchant Energy Group of the Americas (MEGA) for cash consideration of US$12.5 million (Cdn$18.6 million). In June 2001, the corporation purchased the remaining 50 per cent of MEGA for cash consideration of US$0.3 million (Cdn$0.4 million). MEGA specialized in the commercial management of power generation assets in the U.S. and will provide additional market knowledge and capability to enable the acquisition and development of power facilities in the U.S. and will serve as a platform on which to expand trading activities into the eastern U.S. regions. As such, the results of MEGA's operations have been included in the Energy Marketing segment. Previously they had been recorded in the IPP business segment. Prior period amounts have been reclassified to reflect this change. In September 2001, the MEGA operations were amalgamated with TransAlta Energy Marketing (U.S.) Inc., a subsidiary of TransAlta Energy.

The purchase of the initial 50 per cent in 2000 included cash of $7.2 million, a negative working capital balance of $8.8 million, capital and intangible assets of $33.6 million, and future income tax liabilities of $13.4 million. The purchase of the remaining 50 per cent in June 2001 was comprised of negative working capital of $7.7 million, capital and intangible assets of $14.2 million and a future tax liability of $6.1 million.

B. DISPOSALS

In January 2001, the corporation sold its 265 MW Mildred Lake plant to Syncrude's joint venture owners for cash proceeds of $60.3 million plus a receivable in the amount of $4.7 million, which approximated its book value. Of the receivable amount, $0.2 million remains outstanding at Dec. 31, 2002, and is expected to be collected in full by March 2003.

In August 2001, the corporation sold its 45 MW Fort Nelson gas-fired facility for cash proceeds of $44.1 million. The gain on disposition was $1.3 million after-tax. The book value of the assets was $42.8 million.

In September 2001, the corporation sold its 60 per cent interest in the Fort Saskatchewan cogeneration facility to TransAlta Cogeneration, L.P. (TA Cogen), a limited partnership owned 50.01 per cent by the corporation and 49.99 per cent by TransAlta Power, L.P. (TransAlta Power), a publicly owned entity. Total cash consideration to the corporation was $35.0 million in respect of the 30 per cent interest effectively sold to the minority interest in TA Cogen. The corporation recorded a pre-tax gain of $6.2 million. The effective book value of the assets transferred to TA Cogen was $57.6 million, with $28.8 million representing TransAlta Power's 49.99 per cent interest in the assets.

6. Investments

		2002		2001
Investment in Australian gas transmission pipeline	**$**	**21.2**	$	19.2
Investment in distributed generation companies		**10.3**		7.9
Investment in wind power generation		**-**		10.0
Other		**0.7**		0.2
	$	**32.2**	$	37.3

On Dec. 6, 2002, the corporation purchased the remaining portion of Vision Quest, a wind power generation company (Note 5).

7. Long-term receivables

		2002		2001
Sulphur tax abatement	**$**	**60.9**	$	45.0
California receivables		**37.6**		-
Due from Aquila Networks Canada		**-**		173.3
Due from Syncrude Canada Ltd.		**-**		2.3
Other		**2.3**		0.8
		100.8		221.4
Less current portion included in accounts receivable		**60.9**		-
	$	**39.9**	$	221.4

The sulphur tax abatement represents an incentive to coal-fired thermal electric generators in Washington State, U.S., to construct air pollution control facilities. Final certification of meeting the initial rolling 12-month emission requirements is required by Feb. 28, 2004. These requirements have been met, and the abatement is expected to be received in 2003.

The net California accounts receivables of US$24.2 million have been reclassified to long-term receivables, as collection is no longer expected in 2003, although ultimate collection of the net receivable is expected (Note 20).

On Dec. 12, 2002, a U.S. Federal Energy Regulatory Commission (FERC) Administrative Law Judge issued proposed findings of fact that TransAlta be entitled to receive approximately US$44.0 million for electricity sales to California. However, FERC has proposed further adjustments in respect of power and gas prices, which could result in further adjustments to the amount to be received by TransAlta. Until a final ruling is made with respect to these issues, TransAlta will maintain the provision for these receivables. The receivables do not bear interest.

In August 2002, the remaining $180.3 million due from Aquila Networks Canada (formerly UtiliCorp Networks Canada) that arose from the August 2000 sale of the discontinued Alberta D&R operation was collected in full (Note 3).

8. Property, plant and equipment

			2002			2001
	Depreciation rates	**Cost**	**Accumulated depreciation and amortization**	**Net book value**	Cost	Accumulated depreciation and amortization
Mining property & equipment	3% - 50%	**$ 882.7**	**$ 330.6**	**$ 552.1**	$ 850.6	$ 29
Thermal generation	3% - 33%	**3,439.7**	**1,095.0**	**2,344.7**	3,235.4	93
Thermal environmental equipment	4% - 13%	**411.3**	**229.9**	**181.4**	425.2	22
Gas generation	2% - 33%	**1,577.7**	**181.1**	**1,396.6**	1,241.7	18
Hydro generation	2% - 5%	**332.9**	**174.4**	**158.5**	321.3	16
Wind generation	2% - 3%	**54.6**	**-**	**54.6**	-	

Transmission systems	2% - 7%	**43.6**	**8.9**	**34.7**	1,401.8	77
Other	2% - 33%	**175.6**	**69.9**	**105.7**	203.0	9
Assets under construction	-	**1,206.8**	**-**	**1,206.8**	1,087.7	
		$ 8,124.9	**$ 2,089.8**	**$6,035.1**	$ 8,766.7	$ 2,67

Year ended Dec. 31	2002	2001	2000
Capitalized interest	**$ 79.1**	$ 47.3	$ 36.2
Capitalized allowance for funds used during construction	**-**	1.0	3.6

After a detailed engineering assessment, a review of environmental issues and a review of short- and long-term market forecasts, the corporation implemented a phased decommissioning of its 537 MW coal-fired Wabamun facility in November 2002. As a result of this decision, the corporation recorded a pre-tax impairment charge of $110.0 million during the year, included in thermal generation equipment. The impairment charge was calculated as the excess of carrying value over fair value. The fair value of the facility was determined by estimating the present value of future cash flows.

In November 2002, the corporation cancelled orders for four natural gas turbines and as a result recorded a pre-tax impairment charge of $42.5 million for contract termination costs, included in assets under construction. The costs consisted of progress payments made to date.

In September 2001, the corporation reassessed its investment in the 154 MW Pierce Power plant as a result of weak economic conditions. Revenue hedges that were no longer expected to be effective were unwound and realized, resulting in the recognition of $121.8 million of revenue, an impairment charge of $66.5 million, included in gas generation equipment, and $52.3 million in anticipated future operating costs. The plant remained available for production until it was decommissioned in September 2002.

In the fourth quarter of 2000, the corporation recorded a pre-tax impairment charge of $31.7 million ($17.9 million after-tax) related to its discontinued composter facility in Edmonton, Alberta, included in other assets. The composter facility was recorded as a discontinued operation effective Dec. 31, 2000.

9. Other assets

	2002	2001

Deferred license fees	**$**	**26.6**	$	23.9
Deferred financing costs		**24.7**		10.6
Deferred contract costs		**24.9**		-
Cross-currency interest rate swaps (Note 20)		**14.1**		34.0
Foreign currency forward contracts and interest rate swaps (Note 20)		**10.0**		6.4
Deferred project development costs and other		**10.3**		6.2
	$	**110.6**	$	81.1

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 contract.

10. Short-term debt

		2002 Outstanding	**2002 Interest [1]**		2001 Outstanding	2001 Interest [1]
Commercial paper	**$**	**290.0**	**2.7%**	$	207.2	2.4%
Bank debt		**-**	-		330.0	3.5%
	$	**290.0**		$	537.2	

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

11. Long-term debt

A. AMOUNTS OUTSTANDING

2002	**2002**	2001	2001

		Outstanding	**Interest[1]**	Outstanding	Interest[1]
Debentures, due 2003 to 2033 [2]	**$**	**1,863.4**	**6.8%**	$ 1,963.4	7.0%
Senior notes, US$300.0 million [3]		**465.6**	**6.8%**	-	-
Bank credit facility - Campeche, US$133.6 million [4]		**207.3**	**3.1%**	200.5	2.9%
Commercial paper [5]		**84.8**	**1.4%**	257.2	2.3%
Notes payable - Windsor plant, due 2003 to 2014 [6]		**62.1**	**7.4%**	65.3	7.4%
Preferred securities, due 2048 to 2050 [7]		**14.9**	**7.8%**	13.8	7.8%
Capital lease obligation, due 2004 [8]		**8.5**	**9.4%**	10.9	9.4%
		2,706.6		2,511.1	
Less current portion		**355.4**		104.3	
	$	**2,351.2**		$ 2,406.8	

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

[2] DEBENTURES: The debentures bear interest at fixed rates ranging from 5.49 per cent to 8.6 per cent . A floating charge on the property and assets of TransAlta Utilities has been provided as collateral for $798.4 million of the debentures as at Dec. 31, 2002. The interest rate on $375.0 million of the 2002 amount has been converted to floating rates based on bankers' acceptance rates using receive fixed interest rate swaps maturing in 2003 to 2011 (Note 20). 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. Another debenture of $150.0 million maturing in 2005 is extendable until 2030 at the option of the holder.

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[3] SENIOR NOTES: In June 2002, the corporation issued debt of US$300.0 million under a US$1.0 billion shelf prospectus filed May 14, 2002. The notes bear interest at 6.75 per cent and mature on July 15, 2012. This debt has been designated as a hedge of the corporation's net investment in U.S. and Mexican operations (Note 20).

[4] BANK CREDIT FACILITY - CAMPECHE: In December 2000, the corporation established a US$133.6 million 16-year credit facility for the financing of the construction of a gas-fired power plant in Campeche, Mexico. The outstanding borrowing totals US$133.6 million with an interest rate of LIBOR plus 0.875 per cent during construction and LIBOR plus 2.25 per cent upon completion of the construction, increasing to LIBOR plus 3.25 per cent by 2016. Upon completion of construction in March 2003, 70 per cent of the facility will be converted to a fixed rate of 7.4 per cent with a forward starting swap (Note 20). During construction, the corporation has provided a guarantee to the lenders for the completion of the plant. Upon completion, the Campeche plant will be pledged as collateral.

[5] COMMERCIAL PAPER: Amounts outstanding at Dec. 31, 2002 include US$54.6 million of commercial paper. Under the terms of TransAlta's credit facility, the corporation has the ability and intent to maintain these commercial paper borrowings beyond one year. The corporation has designated this commercial paper as a long-term hedge of a portion of its net investment in U.S. and Mexican operations (Note 20).

[6] NOTES PAYABLE - WINDSOR PLANT: The Windsor plant notes payable bear interest at fixed rates and are recourse to the corporation through a standby letter of credit.

[7] PREFERRED SECURITIES: The debt component amount of the preferred securities (Note 14) represents the present value of the principal amount of $475.0 million due in 2048 and 2050. Interest accretion at the coupon rate is included in interest expense.

[8] CAPITAL LEASE OBLIGATION: Certain coal mining assets of TransAlta Utilities have been provided as collateral. The obligation bears interest at a fixed rate.

B. PRINCIPAL REPAYMENTS

Principal repayments over each of the next five years and thereafter are as follows:

2003	$ 355.4
2004	146.9
2005	247.4
2006	364.4
2007	15.7
2008 and thereafter	1,576.8
	$ 2,706.6

C. INTEREST EXPENSE

Interest expense on long-term debt was $161.9 million (2001 - $150.3 million; 2000 - $165.7 million), of which $159.5 million (2001 - $140.6 million; 2000 - $140.7 million) relates to continuing operations.

D. GUARANTEES

In the normal course of operations, TransAlta and certain of its subsidiaries enter into agreements to provide financial or performance assurances to third parties. This includes guarantees, letters of credit and surety bonds which are entered into to support or enhance creditworthiness in order to facilitate the extension of sufficient credit for Energy Marketing trading, treasury hedging and Generation construction projects and equipment purchases.

At Dec. 31, 2002, the corporation had $161.7 million, US$144.4 million and 35.2 million pesos in letters of credit outstanding. The letters of credit were issued to counterparties that have credit exposure to certain subsidiaries. If a subsidiary does not pay amounts due under the covered contract, the counterparty may present its claim for payment to the financial institution, which in turn will request payment from the corporation. Any amounts owed by the corporation's subsidiaries are reflected in the consolidated balance sheet. All letters of credit expire in 2003.

The corporation had a surety bond in the amount of US$156.7 million in support of future site reclamation liabilities at the Centralia mine outstanding at Dec. 31, 2002. A provision for reclamation liabilities is included in the deferred credits and other long-term liabilities (Note 12). The surety bond expires in 2005.

TransAlta has also guaranteed payments for its subsidiaries involved in hedging and trading activities. These guarantees are provided to counterparties in order to facilitate physical and financial transactions in various derivatives. To the extent liabilities exist for trading activities, they are included in the consolidated balance sheet. To the extent liabilities exist for hedging activities, they are disclosed in Note 20. The limit under these guarantees at Dec. 31, 2002 for trading and hedging activities was $1.9 billion. In addition, the corporation has a number of unlimited guarantees. The exposure at Dec. 31, 2002 under these guarantees was approximately $475 million. Certain contracts contain provisions that require collateral to be provided if certain triggers in the contract are met such as fluctuations in commodity prices or creditworthiness. In the absence of any credit limits granted by TransAlta's counterparties, TransAlta's maximum collateral requirements would have been $492.0 million at Dec. 31, 2002 if the corporation's credit ratings were below investment grade. Collateral available was approximately $1 billion.

TransAlta has provided guarantees to counterparties for obligations of various subsidiaries for performance and payment of obligations. In the event of the subsidiaries' inability to meet the obligations, TransAlta would be obligated to make such payments. To the extent obligations exist under these guarantees at Dec. 31, 2002, they are included in accounts payable and accrued liabilities. The limit under these guarantees at Dec. 31, 2002 was $693.8 million.

TransAlta has guaranteed the debt of $269.4 million at Dec. 31, 2002 for the Windsor and Campeche plants. The debt is recorded on TransAlta's consolidated balance sheets. The subsidiaries are required to comply with certain financial covenants as specified in the debt agreements. In the event of default, TransAlta would be obligated to pay the principal and any related interest. Currently, the subsidiaries are in compliance with all covenants, and management does not estimate any difficulties in continuing to maintain compliance. The US$133.6 million of debt related to the Campeche plant will become non-recourse to the corporation upon commencement of commercial operations which is expected to occur in the first quarter of 2003, and the achievement of certain performance tests, which is expected to occur in the second half of 2003.

12. Deferred credits and other long-term liabilities

		2002		2001
Future site restoration costs	**$**	**359.8**	$	339.8
Unamortized gain on sale of assets to limited partnership		**123.7**		131.3
Cross-currency interest rate swaps (Note 20)		**34.3**		70.9
Fair value of swap transaction with limited partnership (Note 22)		**9.7**		13.3
Deferred revenues and other		**12.7**		5.2
	$	**540.2**	$	560.5

The unamortized gain on sale of property, plant and equipment to the limited partnership relates to the gain on disposal of a 49.99 per cent interest in Ontario cogeneration assets held by TA Cogen to TransAlta Power, a publicly owned entity, in 1998. The corporation is obligated to purchase all of TransAlta Power's interest in TA Cogen on Dec. 31, 2018, at the fair market value at that date. Accordingly, the gain of $160.3 million is being deferred and amortized on a straight-line basis over the period to Dec. 31, 2018. Amortization of the gain in the amount of $7.6 million (2001 - $7.7 million; 2000 - $7.7 million) is included in depreciation and amortization expense in the statements of earnings.

13. Non-controlling interests

A. STATEMENTS OF EARNINGS

		2002		2001		2000
TransAlta Power's limited partnership interest in TA Cogen (Note 22)	**$**	**19.0**	$	14.7	$	29.4
Dividend requirements on preferred shares of a subsidiary		**-**		6.1		11.7
Other common shareholders' interests		**1.1**		(0.2)		0.5
	$	**20.1**	$	20.6	$	41.6

On Sept. 10, 2001, the remaining series of preferred shares were redeemed for $121.6 million plus a premium of $0.5 million.

B. BALANCE SHEETS - OTHER NON-CONTROLLING INTERESTS

	2002	2001
TransAlta Power's limited partnership interest in TA Cogen	**$ 263.0**	$ 271.9
Other common shareholders' interests	**-**	9.1
	$ 263.0	$ 281.0

14. Preferred securities

Maturity	Call date	Coupon	2002	2001
2048	2004	7.50%	**$ 165.4**	$ 165.8
2048	2004	8.15%	**119.4**	119.5
2050	2006	7.75%	**166.9**	167.3
			$ 451.7	$ 452.6

In November 2001, the corporation issued preferred securities for net proceeds of $171.9 million (net of issue costs and related tax benefits). The corporation may redeem the preferred securities in whole or in part on or after 2006 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.

In 1999, the corporation issued preferred securities for net proceeds of $294.8 million (net of issue costs and related tax benefits). The corporation may redeem the preferred securities in whole or in part on or after 2004 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. In 1999, the corporation monetized a portion of this redemption feature by writing pay fixed swaptions exercisable in 2004, having a notional amount of $75.0 million and a weighted average interest rate of 6.1 per cent. At Dec. 31, 2002, the swaptions had a fair value liability of $4.6 million (2001 - $1.3 million).

The preferred securities are subordinated and unsecured. The corporation may elect to defer coupon payments on the preferred securities and settle deferred coupon payments in either cash or common shares of the corporation. As a result, the preferred securities are classified into their respective debt (Note 11) and equity components. The above equity component amounts represent the present value of future coupon payments.

Historically, the coupon payments have been settled in cash, and the intent is to continue to do so; therefore, the preferred securities have no dilutive effect on earnings per share. Supplemental diluted earnings per share for 2002 from continuing operations and net earnings as though the coupon payments were settled with shares were $0.34 (2001 - $0.94; 2000 - $0.77) and $1.07 (2001 - $1.18; 2000 - $1.58), respectively (Note 15(D)).

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15. Common shares

A. ISSUED AND OUTSTANDING

The corporation is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2002		2001		2000	
	Common shares (millions)	**Amount**	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**168.3**	**$ 1,170.9**	168.6	$1,150.3	169.2	$ 1,145.9
Repurchased by the corporation	**(2.0)**	**(13.4)**	(2.0)	(14.1)	(1.6)	(10.6)
Issued under dividend reinvestment and share purchase plan	**2.7**	**53.4**	0.9	19.1	0.7	10.4
Issued for cash under stock option plans	**0.1**	**1.8**	0.7	13.8	0.2	2.9
Issued under Performance Share Ownership Plan	**0.1**	**1.9**	0.1	1.8	0.1	1.7
Issued on purchase of Vision Quest	**0.6**	**11.6**	-	-	-	-
Issued and outstanding, end of year	**169.8**	**$ 1,226.2**	168.3	$1,170.9	168.6	$ 1,150.3

In 2002, the corporation purchased for cancellation, under its normal course issuer bid, 1,979,700 common shares (2001 - 2,043,100; 2000 - 1,567,100) in the amount of $40.4 million (2001 - $48.9 million; 2000 - $23.9 million). The $27.0 million (2001 - $34.8 million; 2000 - $7.5 million) excess of the repurchase price over the average net book value was charged to retained earnings. In 2000, the excess of the repurchase price over the average net book value was charged first to contributed surplus and the remainder was charged to retained earnings. Under the terms of the normal course issuer bid program, which expires in February 2003, the corporation is allowed to purchase for cancellation up to 3.0 million of its common shares.

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.

When an acquiring shareholder acquires 20 per cent or more of the outstanding common shares of the corporation and that shareholder does not make a bid for all of the common shares outstanding, each shareholder other than the acquiring shareholder may receive one right for each common share owned. Each right will entitle the holder to acquire an additional $160 worth of common shares for $80.

C. DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the terms of the dividend reinvestment and share purchase plan, participants are able to purchase additional common shares by reinvesting dividends. Common shares will be issued from treasury. In 2002, 2.7 million (2001 - 0.9 million; 2000 - 0.7 million) common shares were purchased under this program for $53.4 million (2001 - $19.1 million; 2000 - $10.4 million).

D. DILUTED EARNINGS PER SHARE

	2002		2001		2000	
	Numerator	**Denominator**	Numerator	Denominator	Numerator	Denominator
Basic EPS from continuing operations	**$ 57.1**	**169.6**	$ 169.5	168.9	$ 133.6	168.8
Impact of PSOP	**-**	**0.1**	(2.7)	0.4	(3.9)	0.3
Diluted EPS from continuing operations	**57.1**	**169.7**	166.8	169.3	129.7	169.1
Impact of preferred securities coupon payment	**-**	**-**	13.1	21.4	-	-
Diluted supplemental EPS from continuing operations	**$ 57.1**	**169.7**	$ 179.9	190.7	$ 129.7	169.1

Options to purchase common shares were not included in the computation of diluted EPS as the exercise price of the options was greater than the average market price of the common shares during the periods. The impact of settling preferred securities' coupon payments in shares did not have a dilutive effect on EPS from continuing operations in 2002 or 2000.

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16. Stock-based compensation plans

At Dec. 31, 2002, 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. MANAGEMENT PLAN: The granting of options under this fixed stock option plan was discontinued in 1997. Options were granted under this plan to certain eligible employees. The options could not be exercised until one year after grant and thereafter at an amount not exceeding 20 per cent of the grant per year on a cumulative basis until the sixth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. CANADIAN EMPLOYEE PLAN: This plan came into effect in 2000 and was 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.

III. ALBERTA D&R PLAN: This plan came into effect in 2000 and was offered to all full-time and part-time employees ofthe Alberta D&R business segment. Options granted under this plan could not be exercised until the date of the closing of the Alberta D&R sale, after which the entire grant could be exercised until the third year, which is the expiry date.

IV. U.S. PLAN: This plan came into effect in 2001 and was offered to all full-time and part-time employees in the U.S. 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.

V. 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.

	Management plan		**Canadian employee plan**		**Alberta D&R plan**		**U.S. employee plan**		**Australian phantom plan**	
	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	Number of share options (millions)	Weighted average exercise price (US$)	Number of share options (millions)	Weighted average exercise price
Outstanding, Jan. 1, 2000	0.8	$ 14.13	-	$ -	-	$ -	-	$ -	-	$ -
Granted	-	-	0.7	14.20	0.1	14.20	-	-	-	-

Exercised	(0.2)	13.37	-	-	-	-	-	-	-	-
Cancelled or expired	-	-	(0.1)	14.20	-	-	-	-	-	-
Outstanding, Dec. 31, 2000	0.6	$ 14.37	0.6	$ 14.20	0.1	$ 14.20	-	$ -	-	$ -
Granted	-	-	0.9	26.96	-	-	0.8	14.19	-	-
Exercised	(0.4)	14.08	(0.1)	14.22	-	-	-	-	-	-
Cancelled or expired	-	-	(0.1)	21.32	-	-	-	-	-	-
Outstanding, Dec. 31, 2001	0.2	$ 14.84	1.3	$ 22.27	0.1	$ 14.20	0.8	$ 14.19	-	$ -
Granted	-	-	0.7	20.92	-	-	0.4	12.51	0.1	22.00
Exercised	(0.1)	14.57	(0.1)	14.23	-	-	-	-	-	-
Cancelled or expired	-	-	(0.3)	22.98	-	-	(0.1)	13.53	-	-
Outstanding, Dec. 31, 2002	0.1	$ 14.91	1.6	$ 21.89	0.1	$ 14.20	1.1	$ 13.61	0.1	$ 22.00

	Options outstanding			**Options exercisable**	
Range of exercise prices	**Number outstanding at Dec. 31, 2002 (millions)**	**Weighted average remaining contractual life (years)**	**Weighted average exercise price**	**Number exercisable at Dec. 31, 2002 (millions)**	**Weighted average exercise price**
$13.12 - $18.00	**0.5**	**5.6**	**$ 14.42**	**0.3**	**$ 14.57**
$18.01 - $23.00	**1.9**	**8.7**	**21.11**	**0.2**	**22.02**
$27.70	**0.6**	**8.3**	**27.70**	**0.1**	**27.70**
$13.12 - $27.70	**3.0**	**8.1**	**$ 21.20**	**0.6**	**$ 19.79**

B. PERFORMANCE STOCK OPTION PLAN

In 1999, the corporation expanded enrolment in the share 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.

	2002		2001		2000	
	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	**0.4**	**$ 22.31**	0.6	$ 21.87	0.9	$ 23.05
Granted	**-**	**-**	-	-	0.1	14.15
Exercised	**(0.1)**	**15.16**	(0.2)	21.27	-	-
Cancelled or expired	**(0.1)**	**22.99**	-	-	(0.4)	22.29
Outstanding, end of year	**0.2**	**$ 22.44**	0.4	$ 22.31	0.6	$ 21.87

At Dec. 31, 2002, the corporation had 16,508 options with an exercise price of $14.15 and a weighted average remaining contractual life of 7.0 years and 223,425 options with an exercise price of $23.05 and a weighted average remaining contractual life of 6.1 years outstanding. At Dec. 31, 2002, 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 awards which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the award 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 a selected group of publicly traded companies. Until Dec. 31, 2001, where common shares were awarded, such shares were then held in trust and therefore could not be disposed of for a period of two additional years.

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.

	2002	2001	2000
Number of awards outstanding, beginning of year	**1.0**	1.0	0.9

Granted	**0.6**	0.4	0.5
Awarded	**(0.1)**	(0.1)	(0.1)
Cancelled or expired	**(0.1)**	(0.3)	(0.3)
Number of awards outstanding, end of year	**1.4**	1.0	1.0

In 2002, PSOP compensation expense was $5.3 million (2001 - $4.8 million; 2000 - $5.1 million), which is included in operations, maintenance and administration expense in the statements of earnings. The first PSOP award maturity occurred in 2000 and 120,101 common shares were issued at $14.15 per share. In 2001, 83,077 common shares were issued at $22.00 per share. In 2002, 84,578 common shares were issued at $21.60 per share.

D. EMPLOYEE SHARE PURCHASE PLAN

Under the terms of the employee share purchase plan implemented in 2000, the corporation will extend an interest-free loan (up to 30 per cent of employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay these loans. Executives are no longer eligible for this program in accordance with 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, 2002, accounts receivable from employees under the plan totalled $1.5 million (2001 - $1.7 million).

The old employee share purchase plan was terminated in 2000 and involved the issuance of up to an aggregate of 200,000 common shares at prices based on the market price of the shares as determined on the date of issue. Employees were able to obtain an interest-free loan, up to 10 per cent of their gross salary, which was repayable over a 12-month period. In 2000, 19,535 common shares were purchased under the old plan and were fully repaid in 2001.

E. STOCK-BASED COMPENSATION

As disclosed in Note 1(P), the corporation adopted the intrinsic value method of accounting for stock-based compensation effective Jan. 1, 2002. The following table provides pro forma measures of net earnings and earnings per share had compensation expense been recognized based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation:

	2002	2001	2000
Reported net earnings applicable to common shareholders	**$ 189.9**	$ 214.6	$ 279.8
Compensation expense	**3.7**	2.0	0.3
Pro forma net earnings applicable to common shareholders	**$ 186.2**	$ 212.6	$ 279.5

Reported basic earnings per share	**$ 1.12**	$ 1.27	$ 1.66
Compensation expense per share	**0.02**	0.01	-
Pro forma basic earnings per share	**$ 1.10**	$ 1.26	$ 1.66
Reported diluted earnings per share	**$ 1.12**	$ 1.25	$ 1.64
Compensation expense per share	**0.02**	0.01	-
Pro forma diluted earnings per share	**$ 1.10**	$ 1.24	$ 1.64

The estimated fair value of these stock options was determined using the binomial model using the following assumptions, resulting in a weighted-average fair value of $4.25 per option (2001 - $4.35; 2000 - $1.86):

	2002	2001	2000
Risk-free interest rate (%)	**5.9**	5.4	5.4
Expected hold period to exercise (years)	**7.0**	7.0	7.0
Volatility in the price of the corporation's shares (%)	**28.3**	28.2	19.6

17. Prior period regulatory decisions

A. 2002 EUB DECISION

On April 16, 2002, the EUB rendered a negative decision of $3.3 million pre-tax with respect to TransAlta's hydro bidding strategy in 2000.

B. 2001 TSR SETTLEMENT

In December 2001, the EUB ruled the Wabamun unit four outage qualified for relief under the TSR and ordered that TransAlta receive $11.0 million ($7.0 million after-tax) to compensate the corporation for obligation payments incurred as a result of the outage.

C. 2000 TSR SETTLEMENT

In September 2000, TransAlta negotiated a settlement resulting in the receipt of $17.8 million ($9.9 million after-tax) under the TSR to compensate the corporation for obligation payments incurred as a result of Alberta Generation production outages which occurred in 1999 and 2000. Approximately $13.5 million ($7.4 million after-tax) related to outages in 1999 and $4.3 million ($2.5 million after-tax) related to outages in 2000.

D. FINAL 1999 DECISION RECORDED IN 2000

On Feb. 1, 2000, the EUB announced an amendment to its 1999 Phase I decision (1999 Final Decision) concerning a 1999 revenue requirement issue that partially offset the effect of its original decision rendered in 1999. The positive impact of the 1999 Final Decision increased pre-tax earnings by $30.6 million ($16.4 million after-tax) and was recorded in 2000. Included in this amount was a reduction in earnings of approximately $0.8 million related to the discontinued Alberta D&R operation.

18. Income taxes

A. STATEMENTS OF EARNINGS

I. RATE RECONCILIATIONS

	2002	2001	2000
Earnings from continuing operations before income taxes & non-controlling interests	**$ 116.2**	$ 293.1	$ 316.5
Statutory Canadian federal and provincial income tax rate	**39.3%**	43.3%	44.6%
Expected taxes on income	**$ 45.6**	$ 126.9	$ 141.2
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(19.9)**	(19.0)	(23.4)
Utilization of previously unrecognized tax losses	**(11.2)**	-	-
Resource allowance net of non-deductible royalties	**(3.1)**	(2.6)	(2.6)
TransAlta Power's share of TA Cogen's partnership income	**(7.7)**	(6.2)	(4.4)
Manufacturing and processing rate reduction	**(3.5)**	(7.9)	(3.0)
Non-deductible costs and other	**4.6**	(0.1)	8.3
Large corporations tax (net of surtax)	**8.0**	7.1	8.3
Asset impairment and equipment cancellation recognized at lower rate	**6.3**	-	-
Effect of tax rate changes	**(1.0)**	(11.4)	2.6
Unrecognized future income tax assets		3.1	1.5

	-		
Income tax expense	**$ 18.1**	$ 89.9	$ 128.5
Effective tax rate	**15.6%**	30.7%	40.6%

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.

II. COMPONENTS OF INCOME TAX EXPENSE

	2002	2001	2000
Current tax expense	**$ 77.8**	$ 47.2	$ 109.3
Future income tax (benefit) expense related to the origination and reversal of temporary differences	**(47.5)**	54.1	16.6
Future income tax (benefit) expense resulting from changes in tax rates or laws	**(1.0)**	(11.4)	2.6
Utilization of previously unrecognized tax losses	**(11.2)**	-	-
Income tax expense	**$ 18.1**	$ 89.9	$ 128.5

B. BALANCE SHEETS

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

	2002	2001
Net operating and capital loss carry forwards	**$ 207.6**	$ 69.3
Future site restoration costs	**125.0**	118.4
Unrealized losses on electricity trading contracts	**74.0**	148.8
Property, plant and equipment	**(661.9)**	(584.0)
Unrealized gains on electricity trading contracts	**(82.4)**	(185.7)
Other deductible temporary differences	**39.6**	44.8
	$ (298.1)	$ (388.4)

Future income taxes are presented on the balance sheet as follows:

		2002	2001
Assets	- current	$ 18.7	$ 16.9
	- long-term	72.2	15.6
Liabilities	- current	(17.1)	(11.8)
	- long-term	(371.9)	(409.1)
		$(298.1)	$ (388.4)

Future income tax assets have not been recognized for the following items:

	Expiry date	2002	2001
Unused tax losses	-	$ -	$ 11.0

The benefits of current and future income taxes credited to equity in the period are as follows:

	2002	2001
Balance sheet - preferred securities issue costs	$ -	$ 2.4
Statement of earnings and retained earnings - preferred securities distributions	$ 14.0	$ 11.3

C. REGULATED OPERATIONS

The following unrecognized amounts relating to the corporation's rate-regulated operations would have been recorded had these operations been non-regulated:

	2002	2001
Balance sheet - unrecognized future income tax assets	$ -	$ 8.7

	2002	2001	2000
Net earnings - unrecognized future income tax recovery	$ 0.3	$ 0.8	$ 110.1

19. Employee future benefits

A. DESCRIPTION

The corporation has registered pension plans in Canada and the U.S. covering substantially all employees of the corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options and in Canada, there is an additional supplemental defined benefit plan for certain employees. 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, 2002. As the Canadian registered plan has a funded surplus, there is no requirement for the corporation to fund the registered plan in 2003. 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 $34.5 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 April 30, 2002.

B. EXPENSE

Dec. 31, 2002	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**$ 4.0**	**$ 1.0**	**$ 0.6**	**$ 5.6**
Interest cost	**21.7**	**1.9**	**1.0**	**24.6**
Expected return on plan assets	**(26.8)**	**-**	**-**	**(26.8)**
Experience loss	**0.2**	**0.2**	**0.5**	**0.9**
Settlement upon sale of Transmission operation (Note 3)	**3.8**	**-**	**(0.5)**	**3.3**
Amortization of net transition obligation (asset)	**(9.2)**	**0.3**	**-**	**(8.9)**
Defined benefit expense (income)	**(6.3)**	**3.4**	**1.6**	**(1.3)**
Defined contribution option expense of registered pension plan	**9.2**	**-**	**-**	**9.2**
Net expense	**$ 2.9**	**$ 3.4**	**$ 1.6**	**$ 7.9**

Dec. 31, 2001	Registered	Supplemental	Other	Total

	Registered	Supplemental	Other	Total
Current service cost	$ 3.9	$ 0.8	$ 0.4	$ 5.1
Interest cost	22.1	1.7	0.9	24.7
Expected return on plan assets	(28.8)	-	-	(28.8)
Amortization of net transition obligation (asset)	(9.3)	0.3	0.3	(8.7)
Defined benefit expense (income)	(12.1)	2.8	1.6	(7.7)
Defined contribution option expense of registered pension plan	9.3	-	-	9.3
Expense (income) before capitalization	(2.8)	2.8	1.6	1.6
Regulatory capitalization to plant and equipment	(0.1)	-	-	(0.1)
Net (income) expense	$ (2.9)	$ 2.8	$ 1.6	$ 1.5

Dec. 31, 2000	Registered	Supplemental	Other	Total
Current service cost	$ 3.2	$ 0.7	$ 0.4	$ 4.3
Interest cost	21.3	1.5	0.7	23.5
Expected return on plan assets	(29.0)	-	-	(29.0)
Curtailment as a result of other post-employment plan changes	-	-	(2.1)	(2.1)
Settlement upon sale of Alberta D&R operation (Note 3)	13.9	-	(1.2)	12.7
Amortization of net transition (asset) obligation	(9.5)	0.3	-	(9.2)
Defined benefit (income) expense	(0.1)	2.5	(2.2)	0.2
Defined contribution option expense of registered pension plan	10.2	-	-	10.2
Expense (income) before capitalization	10.1	2.5	(2.2)	10.4
Regulatory capitalization to plant and equipment	0.5	-	-	0.5
Net expense (income)	$ 10.6	$ 2.5	$(2.2)	$ 10.9

Net amount related to continuing operations for 2002 was an expense of $4.3 million (2001 - expense of $ 1.7 million, 2000 - income of $1.9 million).

C. STATUS OF PLANS

Dec. 31, 2002	**Registered**	**Supplemental**	**Other**
Market value of plan assets	**$ 353.3**	**$ 0.4**	**$ -**
Accrued benefit obligation	**349.8**	**35.5**	**18.2**
Funded status - plan surplus (deficit) [1]	**3.5**	**(35.1)**	**(18.2)**
Amounts not yet recognized in statements of earnings:			
Unamortized transition obligation (asset)	**(73.3)**	**3.6**	**-**
Unamortized net actuarial loss	**50.4**	**9.0**	**7.4**
Total recognized in balance sheets:			
Accrued liability	**$ (19.4)**	**$ (22.5)**	**$ (10.8)**
Amortization period in years (EARSL)	**9**	**9**	**11**

Dec. 31, 2001	Registered	Supplemental	Other
Market value of plan assets	$ 403.4	$ -	$ -
Accrued benefit obligation	345.5	27.5	13.6
Funded status - plan surplus (deficit) [1]	57.9	(27.5)	(13.6)
Amounts not yet recognized in statements of earnings:			
Unamortized transition obligation (asset)	(84.1)	4.0	-
Unamortized net actuarial loss	5.9	2.6	4.4
Total recognized in balance sheets:			
Accrued liability	$ (20.3)	$ (20.9)	$ (9.2)
Amortization period in years (EARSL)	11	11	15

[1] Management intends to use the surplus in the Canadian registered defined benefit option to pay contributions to the registered defined contribution option and the supplemental defined benefit plan.

D. RECONCILIATION OF PLAN ASSETS

	Registered	Supplemental	Other
Market value of plan assets at Dec. 31, 2000	$ 423.5	$ -	$ -
Contributions	0.9	-	-
Transfers to defined contribution option	(9.3)	-	-
Experience adjustment	2.6	-	-
Benefits paid	(25.2)	-	-
Effect of translation on U.S. plans	1.0	-	-
Actual return on plan assets [1]	9.9	-	-
Market value of plan assets at Dec. 31, 2001	$ 403.4	$ -	$ -
Contributions	3.3	0.4	-
Transfers to defined contribution option	(9.2)	-	-
Experience adjustment	0.2	-	-
Transfer to Altalink on sale of Transmission	(11.1)	-	-
Benefits paid	(26.4)	-	-
Effect of translation on U.S. plans	(0.2)	-	-
Actual return on plan assets [1]	(6.7)	-	-
Market value of plan assets at Dec. 31, 2002	**$ 353.3**	**$ 0.4**	**$ -**

[1] Net of expenses

Plan assets include common shares of the corporation having a fair value of $0.6 million at Dec. 31, 2002 (2001 - $0.9 million). The corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2002 (2001 - $0.1 million).

E. RECONCILIATION OF ACCRUED BENEFIT OBLIGATIONS

	Registered	Supplemental	Other
Accrued benefit obligation as at Dec. 31, 2000	$ 323.8	$ 24.6	$ 9.1
Current service cost	3.9	0.8	0.4
Interest cost	22.1	1.7	0.9
Benefits paid	(24.0)	(1.2)	(1.0)
Effects of translation on U.S. plans	1.5	-	0.2
Actuarial loss	18.2	1.6	4.0
Accrued benefit obligation as at Dec. 31, 2001	$ 345.5	$ 27.5	$ 13.6
Current service cost	4.0	1.0	0.6
Interest cost	21.7	1.9	1.0

Benefits paid	(25.1)	(1.3)	(0.9)
Transfer to Altalink on sale of Transmission	(5.6)	-	(0.8)
Effects of translation on U.S. plans	(0.6)	-	(0.1)
Actuarial loss	9.9	6.4	4.8
Accrued benefit obligation as at Dec. 31, 2002	**$ 349.8**	**$ 35.5**	**$ 18.2**

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

Dec. 31, 2002	**Registered**	**Supplemental**	**Other**
Liability discount rate	**6.25% - 6.5%**	**6.25%**	**6.25% - 6.5%**
Expected long-term rate of return on plan assets	**7.0% - 8.5%**	**-**	**-**
Rate of compensation increase (exclusive of promotion increases)	**3.5% - 5.0%**	**3.5%**	**-**
Health care cost escalation	**-**	**-**	**6.6% - 7.0%**[1]
Dental care cost escalation	**-**	**-**	**3.5%**
Provincial health care premium escalation	**-**	**-**	**2.5%**

Dec. 31, 2001	Registered	Supplemental	Other
Liability discount rate	6.5% - 7.0%	6.5%	6.5% - 7.0%
Expected long-term rate of return on plan assets	7.0% - 8.5%	-	-
Rate of compensation increase (exclusive of promotion increases)	3.5% - 5.0%	3.5%	-
Health care cost escalation	-	-	6.6% - 7.0%[1]
Dental care cost escalation	-	-	3.5%
Provincial health care premium escalation	-	-	2.5%

[1] For five years and 5 per cent thereafter for Canadian plans. For U.S. plans, decreasing gradually to 4.5 per cent for 2016 and remaining at that level thereafter.

20. Financial risk management

A. FOREIGN EXCHANGE RATE RISK MANAGEMENT

I . HEDGES OF FOREIGN OPERATIONS The corporation has exposure to changes in the carrying values of its foreign operations as a result of changes in foreign exchange rates. The corporation uses cross-currency interest rate swaps at fixed and floating rate terms, forward sales contracts and direct foreign currency debt to hedge these exposures. The principal component of the cross-currency interest rate swaps and direct foreign currency debt hedge a portion of the carrying value of foreign operations. Translation gains and losses related to these components are deferred and included in CTA in shareholders' equity on a net of tax basis.

The interest component of the cross-currency interest rate swaps and interest on direct foreign currency debt hedge a portion of the future earnings of the foreign operations. Settlement gains and losses are included in earnings as realized.

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

	2002			2001		
	Amount	**Fair value**	**Maturities**	Amount	Fair value	Maturities
Australian dollars	**AUD$296.0**	**$7.9**	**2005 - 2010**	AUD$300.0	$31.2	2002 - 2010
U.S. dollars	**US$634.0**	**($70.1)**	**2003 - 2012**	US$749.0	($76.2)	2002 - 2006

At Dec. 31, 2002, a $14.1 million asset (2001 - $34.0 million) and a $34.3 million liability (2001 - $70.9 million) related to the principal component of the swaps were deferred and recorded in other assets (Note 9) and deferred credits and other long-term liabilities (Note 12), respectively.

In addition, the corporation has designated U.S. dollar denominated long-term debt (Note 11) in the amount of US$488.2 million (2001 - US$289.8 million) as a hedge of its net investment in U.S. and Mexico operations with $11.8 million (2001 - $1.2 million) of related foreign currency losses deferred and included in CTA.

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

	2002			2001		
	Amount	**Fair value**	**Maturities**	Amount	Fair value	Maturities
New Zealand dollars	**NZ$10.5**	**($0.1)**	**2003**	NZ$12.5	($0.1)	2002
U.S. dollars	**US$328.3**	**$3.3**	**2003**	US$43.3	($0.2)	2002

In addition, the corporation has hedged foreign currency denominated long-term intercompany loans to a self-sustaining foreign subsidiary using forward contracts with a notional amount of US$257.9 million (2001 - US$122.9 million) and a fair value liability of US$6.5 million (2001 - US$1.6 million).

II. HEDGES OF FUTURE FOREIGN CURRENCY OBLIGATIONS The corporation has hedged future foreign currency obligations through forward purchase contracts as follows:

			2002			2001	
Currency sold	Currency purchased	**Amount**	**Fair value asset (liability)**	**Maturities**	Amount	Fair value asset (liability)	Maturities
U.S. dollars	Swiss francs	**8.4 Swiss francs**	**$0.1**	**2003**	22.6 Swiss francs	($0.1)	2002
Canadian dollars	U.S. dollars	**US$36.1**	**($0.2)**	**2003 - 2004**	US$196.6	$3.6	2002 - 2004
Canadian dollars	Swiss francs	**4.1 Swiss francs**	**$0.1**	**2003**	-	-	-
Canadian dollars	British pounds	**-**	**-**	**-**	1.8 British Pounds	$0.1	2002

At Dec. 31, 2002, deferred foreign exchange losses of $0.4 million (2001 - $0.2 million) related to these hedges were included in other assets (Note 9).

B. INTEREST RATE RISK MANAGEMENT

I . EXISTING DEBT The corporation has converted the fixed interest rate debt to floating rates through receive fixed interest rate swaps (Note 11) as shown below:

	2002			2001	
Notional	**Fair value of**	**Maturities**	Notional	Fair value	Maturities

		amount		**swaps**		amount		of swaps	
Fixed rate debt	**$**	**375.0**	**$**	**35.1**	**2006 - 2011**	$ 425.0	$	20.9	2003 - 2011

Including the fixed for floating rate swaps above, 25.1 per cent of the corporation's debt is subject to floating interest rates.

The fair value of the corporation's fixed interest long-term debt changes as interest rates change, with details as follows:

	2002		2001	
	Carrying amount	**Fair value**	Carrying amount	Fair value
Long-term debt, including current portion	**$ 2,706.6**	**$ 2,729.1**	$ 2,511.1	$ 2,527.7

II. ANTICIPATED FUTURE DEBT ISSUANCES The corporation uses forward starting interest rate swaps, treasury locks and spread locks to hedge its interest payments on anticipated future debt issuances as shown below:

		2002			2001	
	Amount	**Fair value**	**Maturity**	Amount	Fair value	Maturity
Forward starting interest rate swaps, treasury locks and spread locks	**US$209.1**	**($58.2)**	**2006 - 2011**	US$338.5	($8.3)	2002 - 2016

Maturities of these instruments have resulted in net deferred losses of $5.2 million (2001 - $6.2 million) included in other assets (Note 9).

C. ENERGY COMMODITIES PRICE RISK MANAGEMENT

I . TRADING ACTIVITIES The corporation markets energy derivatives, including physical and financial swaps, forwards and options, to optimize returns from assets, to earn trading revenues and to gain market information. At Dec. 31, 2002, details of the corporation's trading positions were as follows:

	Units (000s)	Fixed price payor notional amounts	Fixed price receiver notional amounts	Maximum term in months
Electricity	**MWh**	**22,763.6**	**22,164.8**	**45**
Natural gas	**GJ**	**71,719.4**	**76,815.5**	**36**
Electrical transmission rights	**MWh**	**16,177.8**	**1,914.0**	**12**

The gross physical and financial volumes traded are as follows:

Electricity (GWh)			
Year ended Dec. 31	**2002**	2001	2000
Physical	**63,015**	18,504	6,365
Financial	**40,061**	9,115	3,135
	103,076	27,619	9,500

Gas (million GJ)			
Year ended Dec. 31	**2002**	2001	2000
Physical	**96.2**	30.6	42.1
Financial	**63.6**	68.7	93.6
	159.8	99.3	135.7

The carrying and fair value of energy commodity trading assets and liabilities included on the balance sheet are as follows:

	2002	2001
Price risk management assets		
- current	**$ 157.8**	$ 137.6
- long-term	**60.7**	71.3
Price risk management liabilities		

- current	**(173.8)**	(114.1)
- long-term	**(50.6)**	(69.0)
	$ (5.9)	$ 25.8

The change in fair value of contracts outstanding at Dec. 31, 2001 compared to 2002 is attributed to the following:

Fair value of contracts outstanding at Dec. 31, 2001	$ 25.8
Fair value of contracts entered into during the period	(2.7)
Contracts realized or settled during the period	(36.6)
Changes in fair values attributable to changes in valuation techniques	-
Changes in fair values attributable to market price changes	7.6
Fair value of contracts outstanding at Dec. 31, 2002	$ (5.9)

II. HEDGING ACTIVITIES The corporation uses energy derivatives, including physical and financial swaps, forwards and options, to manage its exposure to changes in electricity and natural gas prices. At Dec. 31, 2002, details of the corporation's hedging position were as follows:

	Fixed price payor notional amount	Fixed price receiver notional amount	Maximum term in months
Heat rate swaps (000s)	**1,296.6 MWh**	**7,520.3 GJ**	**70**
Commodity hedges (000s)	**2,164.8 MWh**	**13,119.7 GJ**	**12**

The fair value of these swaps total a liability of $12.8 million (2001 - $2.2 million asset).

In addition, the corporation has entered into a number of long-term gas purchase and transportation agreements in the normal course of business to hedge its long-term electricity sales contracts. The maximum term of these contracts is five years.

D. 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, and continually monitors these exposures. For Energy Marketing, the corporation sets strict credit limits for each counterparty and halts trading activities with the counterparty if the limits are exceeded. 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. TransAlta is exposed to minimal credit risk for Alberta Generation PPAs as all receivables are guaranteed by the Alberta government.

At Dec. 31, 2000, the corporation had made a provision of US$28.8 million against US$58.0 million of receivables outstanding related to sales to the California market. US$5.0 million of this amount was received during 2001, however, ultimate collection of the remaining balance remains uncertain. As a result, the provision of established in 2000 remains in place.

The maximum credit exposure to any one customer, excluding the California market receivables discussed above and including the fair value of open trading positions, is $26.1 million.

21. Joint ventures

Joint ventures at Dec. 31, 2002 included the following:

Joint venture	Ownership interest	Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, operated by ATCO
Meridian Joint Venture	50%	Cogeneration plant in Alberta, operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 49.99 per cent interest, to be operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities currently under construction in Alberta, operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia, operated by TransAlta
Goldfields Gas Transmission joint venture	8.8%	Australian pipeline

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:

	2002	2001	2000

Results of operations						
Revenues	**$**	**194.8**	$	215.9	$	229.5
Expenses		**(113.6)**		(130.4)		(158.8)
Proportionate share of net earnings	**$**	**81.2**	$	85.5	$	70.7
Cash flows						
Cash flow from operations	**$**	**118.2**	$	84.2	$	18.0
Cash flow from (used in) investing activities		**36.5**		(13.9)		(17.8)
Cash flow from (used in) financing activities		**(16.7)**		(8.3)		(35.0)
Proportionate share of increase in cash and cash equivalents	**$**	**138.0**	$	62.0	$	(34.8)
Financial position						
Current assets	**$**	**35.2**	$	175.8		
Long-term assets		**643.3**		631.3		
Current liabilities		**(18.6)**		(155.7)		
Long-term liabilities		**(18.7)**		(17.9)		
Proportionate share of net assets	**$**	**641.2**	$	633.5		

22. Related party transactions

For the period November 2002 to November 2007, TA Cogen entered into a transportation swap transaction with a wholly owned subsidiary of TransAlta. As described in Note 12, TA Cogen is owned 49.99 per cent by TransAlta Power, a publicly owned limited partnership with the remaining 50.01 per cent owned by TransAlta Energy, which also operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. The business purpose of the transportation swap was to provide TA Cogen with the delivery of fixed price gas, without being exposed to escalating costs of pipeline transportation for two of its plants, over the period of the swap in order to stabilize cash distributions in TA Cogen. This preserves the value of the limited partnership as a financing vehicle for TransAlta. The notional gas volume in the transaction was the total delivered fuel for both 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.

In September 2001, the corporation sold its 60 per cent interest in its Fort Saskatchewan plant to TA Cogen for an after-tax gain of $5.0 million (Note 5).

In November 2000, TA Cogen entered into a fixed-for-floating gas swap transaction with TransAlta Energy for a 61-month period starting Dec. 1, 2000. The swap transaction provides TA Cogen with fixed price gas for both the Mississauga and Ottawa plants over the period. The floating prices associated with the Mississauga and Ottawa cogen plants' long-term fuel supply agreements were transferred to TransAlta Energy's account. The notional gas volume in the transaction was the total delivered fuel for both facilities. As consideration and in negotiation, TA Cogen transferred the right to incremental revenues associated with curtailed electrical production and subsequent higher revenue gas sales. At Dec. 31, 2002, the portion of the contract related to the minority interest had a fair value liability of $9.7 million (2001 - $13.3 million liability).

23. Commitments

A significant portion of the corporation's electricity and thermal sales revenues are subject to long-term contracts and arrangements. Commencing Jan. 1, 2001, Alberta Generation 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 to be supplied by each plant or unit and the price at which each megawatt-hour will be supplied to the customer. A significant portion of production from the Centralia plant 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.

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. In addition, the corporation has committed to purchase turbines for a total purchase price of $53.4 million, and has entered into a number of operating lease agreements and commitments under mining agreements. During the year, the corporation cancelled orders on several turbines, and incurred a pre-tax impairment charge of $42.5 million (Note 8). Approximate future payments under the turbine commitments, operating lease and mining agreements are as follows:

	Operating leases	**Turbines**	**Mining agreements**	**Total**
2003	$ 6.7	$ 6.2	$ 20.0	$ 32.9
2004	5.7	46.0	20.0	71.7
2005	5.5	1.2	20.0	26.7
2006	4.4	-	20.0	24.4
2007	3.2	-	20.0	23.2
2008 and thereafter	26.7	-	357.5	384.2
	$ 52.2	$ 53.4	$ 457.5	$ 563.1

24. Other contingencies

In August 2000, a single thermal generating unit at the Wabamun plant was shut down due to safety concerns related to possible corrosion fatigue cracks within the waterwall tubing of its boiler. Repairs were completed late in the second quarter of 2001 and the unit returned to service in June 2001. Since Jan. 1, 2001, the unit has been subject to the terms of a PPA. Under the PPA's force majeure article, the corporation is not obligated to supply electricity during the period of repair, subject to confirmation by the administrator of the PPAs. Had such confirmation not occurred, the corporation would have been obligated to pay a penalty equal to the cost of obtaining an alternate source of electricity to fulfill its PPA supply obligations during the affected period. The force majeure decision went to arbitration in July 2001. On May 23, 2002, the arbitrators confirmed in their ruling that the outage qualified as a force majeure event, but also ruled that the corporation should have returned the unit to service more quickly. As a result of the decision, the corporation was required to pay $38.9 million plus interest of $2.7 million, all pre-tax. The payment was recorded as an offset to revenues.

On May 8, 2002, FERC requested that 150 sellers of wholesale electricity and ancillary services to the California electricity market, including TransAlta, respond to questions regarding their trading strategies in California during 2000 and 2001. TransAlta has responded to the FERC request and believes it operated in accordance with all applicable laws, rules, regulations and tariffs.

On May 21 and 22, 2002, FERC issued two additional requests for information regarding 'round-trip' trading activities, to which TransAlta responded, stating that the corporation does not believe it participated in any round-trip trades during 2000 and 2001. In addition, Reliant Energy Inc. issued a statement that it engaged in round-trip trades in 1999 with MEGA. TransAlta acquired an initial 50 per cent interest in MEGA in June 2000, and acquired the remaining 50 per cent in June 2001. TransAlta contends that no round-trip trading occurred between Reliant Energy Inc. and MEGA during any period in which TransAlta had an ownership interest in MEGA. TransAlta will continue to cooperate with the regulators and supply all information requested.

On May 30, 2002, the California Attorney General's Office (CAGO) filed civil complaints in the state court of California against eight additional wholesale power companies, including TransAlta. The complaint alleges violations of California's unfair business practices law in connection with rates charged for wholesale electricity sales. TransAlta believes that it has complied with applicable laws in regard to this complaint. In particular, the company is of the view that the basis of the complaint is a matter of federal rather than state jurisdiction. FERC has previously rejected allegations made by CAGO that TransAlta's subsidiaries violated rate filing requirements. On June 26, 2002, TransAlta filed a Notice of Motion to dismiss the complaint.

On Sept. 9, 2002, the Commodities Futures Trading Commission requested information on similar issues. TransAlta has provided the requested information.

On Dec. 16 and 20, 2002, two class action lawsuits on behalf of all persons and businesses in the states of Oregon and Washington were initiated in respect of alleged unlawful practices in the purchase and sale of wholesale energy. TransAlta believes these are without merit and will vigorously defend its actions. No amount has been accrued in these financial statements as neither the amount of the claim nor the outcome was determinable at the reporting date.

On Dec. 16, 2002, the Canadian government ratified the Kyoto Protocol. The Kyoto Protocol is not expected to have an impact on TransAlta's U.S., Mexican or Australian operations.. TransAlta is not able to estimate the full impact the Protocol will have on its Canadian operations, as the Canadian government has not yet established an implementation plan. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change of Law' provisions that may provide an opportunity to recover compliance costs from the PPA customers.

25. Comparative figures

Certain of the comparative figures have been reclassified to conform with the current year's presentation.

26. Subsequent events

On Jan. 13, 2003, TransAlta and EPCOR Utilities Inc. (EPCOR) announced an agreement whereby TransAlta will acquire a 50 per cent interest in EPCOR's Genesee 3 project for $395.0 million. On the same date, TransAlta made a $157.0 million payment to EPCOR for TransAlta's share of project costs incurred to date. The 450 MW addition to the existing Genesee Generating station is currently under construction and expected to commence commercial operations in early 2005. Included in the arrangement is an option for EPCOR to puchase a 50 per cent interest in TransAlta's Centennial 1 project, formerly referred to as Keephills 3. The option expires Dec. 31, 2005. EPCOR also has the option to purchase a 50 per cent interest in TransAlta's Sarnia plant, which may be exercised between January 2003 and March 2004. TransAlta's interest will be proportionately consolidated.

On Jan. 24, 2003, the corporation announced the acquisition of a 50 per cent interest in CE Generation LLC (CE Gen) for US$205.0 million (approximately Cdn$312 million) plus approximately US$35 million of working capital (approximately Cdn$53 million) and the assumption of non-recourse debt of approximately US$500 million (approximately Cdn$762 million). The acquisition will be accounted for using the purchase method of accounting. CE Gen is controlled jointly by TransAlta and MidAmerican Energy Holdings Company. As such, the financial results of CE Gen will be proportionately consolidated with those of TransAlta. The transaction closed on Jan. 29, 2003. CE Gen holds 816 MW of operating capacity, including 326 MW of geothermal generation in California and 490 MW of gas-fired cogeneration in New York, Texas and Arizona. Due to the timing of the purchase, it was impractical to complete the allocation prior to issuance of the financial statements. The purchase equation will be finalized and disclosed with the first quarter of 2003 results.

On March 14, 2003, the corporation filed a short-form prospectus for the issuance of 12.0 million common shares for gross proceeds of $192.0 million. The underwriters also exercised an option for an additional 3.0 million common shares for gross proceeds of $48.0 million. The offering includes a second option for the underwriters to purchase a further 2.25 million common shares for $36.0 million, exercisable until April 18, 2003. The transaction is expected to close on March 21, 2003.

27. U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP, which, in most respects, conform to accounting principles generally accepted in the U.S. (U.S. GAAP). Significant differences between Canadian and U.S. GAAP are as follows:

A. EARNINGS AND EPS

	Reconciling items	**2002**	2001	2000
Earnings from continuing operations - Canadian GAAP		**$ 78.0**	$ 182.6	$ 146.4
Derivatives and hedging activities, net of tax	(I)	**(3.8)**	20.0	(4.2)
Start-up costs, net of tax	(II)	**(4.5)**	3.6	10.5
Preferred securities distributions, net of tax	(III)	**(20.9)**	(13.1)	(12.8)
Amortization of debt extinguishment, net of tax	(IV)	**0.8**	0.8	0.8
Income taxes - rate change adjustment	(V)	**-**	20.0	2.6
Amortization of pension transition adjustment	(VI)	**(5.8)**	(4.5)	-
Earnings from continuing operations - U.S. GAAP		**43.8**	209.4	143.3
Earnings from discontinued operations - Canadian and U.S. GAAP		**12.8**	45.1	89.1
Net gain on disposal of discontinued operations - Canadian and U.S. GAAP		**120.0**	-	266.8
Net earnings before extraordinary items and change in accounting principle - U.S. GAAP		**176.6**	254.5	499.2
Extraordinary loss - Canadian GAAP		**-**	-	209.7
Income taxes - rate change adjustment	(V)	**-**	-	22.6
Employee future benefits	(VI)	**-**	-	(30.3)
Extraordinary loss - U.S. GAAP		**-**	-	202.0
Net earnings before change in accounting principle - U.S. GAAP		**176.6**	254.5	297.2
Cumulative effect of change in accounting principle, net of tax	(I)	**-**	0.2	-
Net income - U.S. GAAP		**$ 176.6**	$ 254.7	**$ 297.2**
	(I), (VIII)		(38.5)	

Cumulative effect of change in accounting principle, net of tax		**-**		-
Foreign currency cumulative translation adjustment	(I), (VIII)	**(16.8)**	(5.4)	19.6
Net gain (loss) on derivative instruments	(I), (VIII)	**(51.5)**	10.0	-
Registered pension alternate minimum liability	(VI)	**(1.7)**	-	-
Comprehensive income - U.S. GAAP		**$ 106.6**	$ 220.8	**$ 316.8**

Basic EPS - U.S. GAAP			
Earnings from continuing operations	**$ 0.26**	$ 1.24	$ 0.85
Earnings from discontinued operations	**0.07**	0.27	0.53
Gain on disposal of discontinued operations	**0.71**	-	1.58
Extraordinary loss	**-**	-	(1.20)
Net earnings	**$ 1.04**	$ 1.51	$ 1.76
Diluted EPS - U.S. GAAP			
Earnings from continuing operations	**$ 0.26**	$ 1.22	$ 0.83
Earnings from discontinued operations	**0.07**	0.27	0.53
Gain on disposal of discontinued operations	**0.71**	-	1.58
Extraordinary loss	**-**	-	(1.20)
Net earnings	**$ 1.04**	$ 1.49	$ 1.74

B.

BALANCE SHEET INFORMATION

	Reconciling items	**2002**		2001	
		Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets					
Current derivative assets	(I)	**$ -**	**$ 8.3**	$ -	$ 58.5
Accounts receivable	(IX)	**626.2**	**624.7**	625.3	623.6

Future or deferred income tax assets - current	(V)	**18.7**	**18.7**	16.9	25.6
Income taxes receivable	(I), (II), (IV)	**111.5**	**120.7**	128.3	136.9
Investments	(X)	**32.2**	**271.9**	37.3	227.8
Property, plant and equipment, net	(II)	**6,035.1**	**6,043.5**	6,094.8	6,110.9
Regulatory rate-making liability	(V)	**-**	**-**	-	(8.7)
Long-term derivative asset	(I)	**-**	**53.3**	-	54.1
Other assets	(I), (II), (III)	**110.6**	**57.4**	81.1	52.3
Liabilities					
Accounts payable and accrued liabilities	(VI)	**646.0**	**610.5**	472.2	425.4
Current derivative liability	(I)	**-**	**27.6**	-	21.5
Long-term debt	(I), (III), (X)	**2,351.2**	**3,087.6**	2,406.8	3,080.2
Deferred credits and other long-term liabilities	(I), (IV)	**540.2**	**526.9**	560.5	532.7
Firm commitments	(I)	**-**	**-**	-	3.6
Long-term derivative liabilities	(I)	**-**	**133.1**	-	134.3
Future or deferred income tax liability	(I), (II), (III), (IV), (V), (VI)	**371.9**	**339.1**	409.1	416.6
Equity					
Preferred securities	(III)	**451.7**	**-**	452.6	-
Common shares	(IX)	**1,226.2**	**1,224.7**	1,170.9	1,169.2
Retained earnings	(I), (II), (IV), (V), (VI)	**832.2**	**839.0**	838.3	858.4
Cumulative translation adjustment	(I), (VIII)	**(18.8)**	**-**	(19.5)	-
Accumulated other comprehensive income	(I), (VIII)	**-**	**(123.7)**	-	(53.7)

C.

RECONCILING ITEMS

I. Derivatives and hedging activities

On Jan. 1, 2001, the corporation adopted Statement 133, Accounting for Derivative Instruments and Hedging Activities. The new statement requires all derivative instruments to be recorded on the balance sheet at fair value, with changes in fair value recognized in earnings in the period of change. If the derivative is designated and qualifies as a fair value hedge, the changes in fair value of the derivative and the hedged item attributable to the hedged risk are recognized in earnings in the period the change occurs. If the derivative is designated and qualifies as a cash flow hedge, the effective portion of changes in the fair value of the derivative are recorded in other comprehensive income (OCI) and are recognized in earnings as the hedged item affects earnings. The ineffective portion of changes in fair value of cash flow hedges is recognized in earnings. If the derivative is designated and qualifies as a hedge of a net investment in a foreign currency, the effective portion of changes in fair value are recorded in OCI as part of CTA and the ineffective portion is recognized in earnings.

The adoption of Statement 133 on Jan. 1, 2001 resulted in the recognition of additional derivative assets with a fair value of $1.6 million, firm commitment assets with a fair value of $0.6 million, additional derivative liabilities with a fair value of $88.6 million, a $0.3 million ($0.2 million after-tax) credit to income as the cumulative effect of a change in accounting principle and a charge of $64.4 million ($38.5 million after-tax) to OCI as the cumulative effect of a change in accounting principle.

(i) FAIR VALUE HEDGING STRATEGY

The corporation enters into forward exchange contracts to hedge certain firm commitments denominated in foreign currencies to protect against adverse changes in exchange rates and uses interest rate swaps to manage interest rate exposure. The swaps modify exposure to interest rate risk by converting a portion of the corporation's fixed-rate debt to a floating rate.

The corporation's fair value hedges resulted in a net gain of $nil related to the ineffective portion of its hedging instruments (inclusive of the time value of money) as well as the portion of the hedging instrument excluded from the assessment of hedge effectiveness.

(ii) CASH FLOW HEDGING STRATEGY

The corporation uses forward-starting swaps, treasury locks and spread locks to hedge the interest rates of anticipated issuances of debt to protect the corporation against increases in interest rates prior to the date of issuance, and uses forward sales contracts and futures contracts to hedge generation production to protect the corporation against fluctuations in commodity prices. The maximum term of cash flow hedges of anticipated transactions is 11 years.

The corporation's cash flow hedges resulted in a net gain of $nil related to the ineffective portion of its hedging instruments as well as the portion of the hedging instrument excluded from the assessment of hedge effectiveness.

In June 2002, forward starting swaps with a notional amount of US$125.0 million were settled and debt was issued, resulting in a loss of $11.2 million. The loss will be reclassified from OCI over 10 years, the term of the hedged debt.

Over the next 12 months, the corporation estimates that $0.7 million of net losses that arose from cash flow hedges will be reclassified from OCI to net earnings. The corporation also estimates that $4.3 million of net losses on cash flow hedging instruments that arose on adoption of Statement 133 will be reclassified from accumulated other comprehensive income (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 OCI to earnings (positive or negative) will be for the next 12 months.

(iii) NET INVESTMENT HEDGES

The company uses cross-currency interest rate swaps, forward sales contracts and direct foreign currency debt to hedge its exposure to changes in the carrying value of its investments in its foreign subsidiaries in the U.S., Australia and Mexico. Realized and unrealized gains and losses from these hedges are included in OCI, with the related amounts due to or from counterparties included in other assets, long-term debt and other liabilities.

The corporation recognized a net after-tax loss of $16.8 million (2001 - $5.4 million gain) on its net investment hedges, included in OCI. .

The corporation recognized income of $nil (2001 - $nil), related to ineffectiveness of net investment hedges.

(iv) TRADING ACTIVITIES

As disclosed in Note 20, the corporation markets energy derivatives to optimize returns from assets, to earn trading revenues and to gain market information. Derivatives, as defined under Statement 133, are recorded on the balance sheet at fair value under both Canadian and U.S. GAAP. Non-derivative contracts entered into subsequent to the rescission of EITF 98-10 are accounted for using the accrual method. Prior to the rescission of EITF 98-10, non-derivative contracts were accounted for using mark-to-model accounting.

(v) OTHER HEDGING ACTIVITIES

The corporation recognized pre-tax income of $1.1 million (2001 - $39.4 million) related to hedging activities that do not qualify for hedge accounting under Statement 133.

II. Start-up costs

Under U.S. GAAP, certain start-up costs, including revenues and expenses in the pre-operating period, are expensed rather than capitalized to deferred charges and property, plant and equipment as under Canadian GAAP, which also results in decreased depreciation and amortization expense under U.S. GAAP.

III. Preferred securities

Under U.S. GAAP, the corporation's preferred securities are considered to be entirely debt with no equity component, whereas under Canadian GAAP, these preferred securities have both a debt and equity component. Accordingly, the preferred securities distributions are classified as an expense under U.S. GAAP rather than a direct charge to retained earnings. Under U.S. GAAP, the costs associated with the issuance of the preferred securities are recorded as an asset whereas under Canadian GAAP, these costs, net of tax, are charged to preferred securities. The fair value of the preferred securities at Dec. 31, 2002 was $504.5 million (2001 - $485.5 million).

IV. Debt extinguishment

Under U.S. GAAP, the premium on redemption of long-term debt related to the limited partnership transaction was recorded as an extraordinary loss when incurred, whereas for Canadian GAAP the loss is amortized to earnings over the period of the limited partnership to 2018.

V. Income taxes

Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP. Canadian and U.S. GAAP require accounting for income taxes using the liability method of tax allocation; however, two significant differences remain between Canadian and U.S. GAAP:

(i) Canadian GAAP requires that future income tax balances be adjusted to reflect substantively enacted rates rather than currently legislated tax rates under U.S. GAAP. As a result of this difference, a $nil (2001 - $20.0 million; 2000 - $2.6 million) adjustment to earnings from continuing operations was required; and

(ii) Under Canadian GAAP, rate-regulated operations need not recognize future income taxes to the extent that future income taxes are expected to be included in the rates charged to and recovered from customers. For these operations, U.S. GAAP requires that the corporation record deferred income tax assets or liabilities for its rate-regulated operations. As these amounts are recoverable or payable through future revenues, a corresponding regulatory rate-making asset or liability is recorded for U.S. GAAP purposes.

Deferred income taxes under U.S. GAAP would be as follows:

	2002	2001
Future income tax liability (net) under Canadian GAAP	**$ (298.1)**	$ (388.4)
Rate-regulated operations deferred income taxes		8.7

	-	
Derivatives	**48.8**	15.6
Start-up costs	**(2.3)**	(2.3)
Preferred securities	**(6.2)**	(6.2)
Debt extinguishment	**9.7**	9.7
Employee future benefits	**(17.2)**	(24.3)
Difference related to rate change adjustment	**-**	-
	$ (265.3)	$ (387.2)

Comprised of the following:

	2002	2001
Current deferred income tax assets	**$ 18.7**	$ 25.6
Long-term deferred income tax assets	**72.2**	15.6
Current deferred income tax liabilities	**(17.1)**	(11.8)
Long-term deferred income tax liabilities	**(339.1)**	(416.6)
	$ (265.3)	$ (387.2)

VI. Employee future benefits

U.S. GAAP requires that the cost of employee pension benefits be determined using the accrual method with application from 1989. It was not feasible to apply this standard using this effective date. The transition asset as at Jan. 1, 1998 was determined in accordance with elected practice prescribed by the Securities and Exchange Commission (SEC) and is amortized over 10 years. The difference between U.S. GAAP and Canadian GAAP for the corporation's regulated operations has no effect on net earnings and retained earnings, as any difference from the allowed method of recovery is recognized as a regulatory rate-making liability refundable through regulation. As indicated in Note 4, the corporation discontinued regulatory accounting and commenced the application of Canadian GAAP for non-regulated entities consistent with the deregulation of the electricity generation industry in Alberta beginning Jan. 1, 2001.

Sensitivity to changes in assumed health care cost trend rates are as follows:

	One percentage point increase	One percentage point decrease
Effect on total service and interest costs	$ 0.3	$ (0.4)
Effect on post-retirement benefit obligation	$ 2.8	$ (4.5)

As a result of the corporation's plan asset return experience for its U.S. registered pension plan, at Dec. 31, 2002, the corporation was required under U.S. GAAP to recognize an additional minimum liability. The liability was recorded as a reduction in common equity through a charge to OCI, and did not affect net income for 2002. The charge to OCI will be restored through common equity in future periods to the extent fair value of trust assets exceed the accumulated benefit obligation.

VII. Joint ventures

In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the SEC, the corporation, as a Foreign Private Issuer, has elected for the purpose of this reconciliation to account for incorporated joint ventures by the proportionate consolidation method.

VIII. Other comprehensive income

The changes in the components of OCI were as follows:

	2002	2001	2000
Cumulative effect of accounting change, net of tax	**$ -**	$ (38.5)	$ -
Net gain (loss) on derivative instruments:			
Unrealized gains (losses), net of taxes of $24.2 million	**(55.5)**	0.5	-
Reclassification adjustment for losses included in net income, net of taxes of $2.2 million	**4.0**	9.5	-
Net gain (loss) on derivative instruments	**(51.5)**	10.0	-
Registered pension alternate minimum liability	**(1.7)**	-	-
Translation adjustments	**(16.8)**	(5.4)	19.6
Other comprehensive income (loss)	**$ (70.0)**	$ (33.9)	$ 19.6

The components of AOCI were:

	2002	2001
Net loss on derivative instruments	**$ (80.0)**	$ (28.5)
Registered pension alternate minimum liability	**(1.7)**	-
Translation adjustments	**(42.0)**	(25.2)
Accumulated other comprehensive loss	**$ (123.7)**	$ (53.7)

IX. SHARE CAPITAL Under U.S. GAAP, amounts receivable for share capital should be recorded as a deduction from shareholders' equity. Under the corporation's employee share purchase plan, accounts receivable for share purchases at Dec. 31, 2002 was $1.5 million (2001 - $1.7 million).

X. RIGHT OF OFFSET AGREEMENT The corporation has a New Zealand bank deposit that has been offset with a New Zealand bank facility under a right of offset agreement. The arrangement does not qualify for offsetting under U.S. GAAP.

D.

FUTURE CHANGES IN ACCOUNTING STANDARDS

In August 2001, the Financial Accounting Standards Board (FASB) issued Statement 143, Asset Retirement Obligations, which requires asset retirement obligations to be measured at fair value and recognized when the obligation is incurred. A corresponding amount is capitalized as part of the asset's carrying amount and depreciated over the asset's useful life. Statement 143 is effective for fiscal years beginning after June 15, 2002, with earlier application encouraged. TransAlta will adopt the provisions of Statement 143 effective Jan. 1, 2003. The expected impact of the adoption of Statement 143 on TransAlta's financial statements has not been finalized.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, which requires the consolidation of entities if certain criteria are met. The Interpretation is effective for fiscal years beginning on or after June 15, 2003. The corporation is currently reviewing the Interpretation to determine whether it will have any impact on the consolidated financial statements of TransAlta Corporation.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

<u>TransAlta Corporation</u>

(Registrant)

By:<u>/s/ Alison T. Love</u>

(Signature)

Alison T. Love, Corporate Secretary

Date: March 27, 2003

CERTIFICATIONS

I, Stephen G. Snyder, certify that:

1.

I have reviewed this Report of Foreign Private Issuer on Form 6-K of TransAlta Corporation;

2.

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3.

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4.

The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the Evaluation Date); and

c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5.

The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weakness in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6.

The registrant's other certifying officer and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date:

March 27, 2003

/s/ Stephen G. Snyder

Stephen G. Snyder

President and Chief Executive Officer

I, Ian Bourne, certify that:

1.

I have reviewed this Report of Foreign Private Issuer on Form 6-K of TransAlta Corporation;

2.

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3.

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4.

The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the Evaluation Date); and

c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5.

The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weakness in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6.

The registrant's other certifying officer and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

/s/ Ian Bourne

Ian Bourne

Executive Vice President and Chief Financial Officer