TRANSALTA CORP
Form 40-F
March 16, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

[Check one]

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

ý **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008
Commission file number 001-15214

TRANSALTA CORPORATION

(Exact name of Registrant as specified in its charter)

Not applicable	**Canada**	**4911**	**Not Applicable**
(Translation of Registrant's name into English (if applicable))	(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S Employer Identification Number (if applicable))

110-12th Avenue S.W., Box 1900, Station "M",
Calgary, Alberta, Canada, T2P 2M1,
(403) 267-7110
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System, 111 8th Avenue, 13th Floor,
New York, New York, 10011, (212) 894-8400
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered

Common Shares, no par value	**New York Stock Exchange**
Common Share Purchase Rights	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

ý Annual information form ý Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

At December 31, 2008, 197,622,215 common shares were issued and outstanding.

Indicate by check mark whether the Registrant by filing 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 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes o 82-____

No ý

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No o

INCORPORATION BY REFERENCE

The documents (or portions thereof) forming part of this Form 40-F are incorporated by reference into the following registration statements under the Securities Act of 1933, as amended.

Form	Registration No.
S-8	333-72454
S-8	333-101470
F-10	333-155243

CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION & ANALYSIS

A. Consolidated Audited Annual Financial Statements

For consolidated audited annual financial statements, including the report of independent chartered accountants with respect thereto, see pages **66** through 111 of the TransAlta Corporation 2008 Annual Report to shareholders included herein. See Exhibit 13.4 for the related supplementary note entitled "Reconciliation to United States Generally Accepted Accounting Principles" for a reconciliation of the important differences between Canadian and United States generally accepted accounting principles.

B. Management's Discussion & Analysis

For management's discussion & analysis, see pages 19 through 65 of the TransAlta Corporation 2008 Annual Report to shareholders included herein under the heading "Management's Discussion & Analysis."

For the purposes of this Form 40-F, only pages 66 through 111 and 19 through 65 of the TransAlta Corporation 2008 Annual Report to shareholders as referred to above shall be deemed incorporated herein by reference and filed, and the balance of such 2008 Annual Report, except as otherwise specifically incorporated by reference in the TransAlta Corporation Annual Information Form filed as Exhibit 13.1 hereto, shall not be deemed to be filed under the Exchange Act with the Securities and Exchange Commission as part of this Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934, management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2008, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

**MANAGEMENT'S REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING**

Management is responsible for establishing and maintaining adequate internal control over financial reporting.

Internal control over financial reporting refers to a process designed by, or under the supervision of, our chief executive officer and chief financial officer and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and members of our board of directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management evaluated the effectiveness of our internal control over financial reporting as of December 31, 2008 using the framework set forth in the report of the Treadway Commission's Committee of Sponsoring Organizations (COSO), "Internal Control Integrated Framework." Management has concluded that our internal control over financial reporting was effective as of December 31, 2008. Certain matters relating to the scope of Management's evaluation and limitations of management's conclusions are described below. See "Limitations and Scope of Management's Report on Internal Control over Financial Reporting."

Our independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2008. For Ernst & Young LLP's report see page 68 of the TransAlta Corporation 2008 Annual Report to shareholders under the heading "Independent Auditors' Report on Internal Controls Under Standards of the Public Company Accounting Oversight Board (United States)".

There has been no change in the internal control over financial reporting during the year covered by this report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

**LIMITATIONS AND SCOPE OF MANAGEMENT'S
REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING**

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

Management has not evaluated the internal controls of the Sheerness, CE Generation and Genesee 3 joint ventures (collectively, the "Excluded Entities"), in accordance with Frequently Asked Question No. 1, "Management's Report on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports," of the Office of the Chief Accountant of the Division of Corporation Finance of the U.S. Securities and Exchange Commission (revised Oct. 6, 2004). Accordingly, management's evaluation of the Company's internal control over financial reporting did not include an evaluation of the internal controls of any of the Excluded Entities, and management's conclusion regarding the effectiveness of the Company's internal control over financial reporting does not extend to the internal controls of any of the Excluded Entities.

Proportionate consolidation of the Excluded Entities contributes to the Company's financial statements in the amount of $1,680 million of the Company's total assets, $747 million of net assets, $481 million of revenues and $53 million of operating income. The Company's financial statements include the accounts of the Excluded Entities, accounted for via proportionate consolidation, in accordance with EITF 00-1, but management has been unable to assess the effectiveness of internal control at the Excluded Entities because the Company does not have the ability to dictate or modify the controls of the Excluded Entities and does not have the ability, in practice, to assess those controls.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's board of directors has determined that it has at least one audit committee financial expert serving on its Audit and Risk Committee (the "ARC"). Mr. William D. Anderson has been determined to be an audit committee financial expert, within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley"), and is independent, as that term is defined by the New York Stock Exchange's ("NYSE") listing standards applicable to the Registrant. Mr. Gordon S. Lackenbauer has also been determined to be an audit committee financial expert for purposes of Section 407 of Sarbanes-Oxley and independent under the applicable NYSE listing standards. Under Securities and Exchange Commission rules the designation of persons as audit committee financial experts does not make them "experts" for any other purpose, impose any duties, obligations or liability on them that are greater than those imposed on members of their committee and the board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of their committee.

CODE OF ETHICS

The Registrant has adopted a code of ethics as part of its "Corporate Code of Conduct" that applies to all employees and officers which has been filed with the SEC. In addition, the Registrant has adopted a code of conduct applicable to all directors of the Company and a separate financial code of conduct which applies to all financial management employees. The Registrant's Corporate Codes of Conduct are available on its Internet website at www.transalta.com. There has been no waiver of the codes granted during the 2008 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2008 and 2007, Ernst & Young LLP and its affiliates were paid approximately $3,372,142 and $2,838,740 respectively, as detailed below:

	Year-ended December 31	
	2008	**2007**
Ernst & Young LLP		
Audit Fees	$2,594,183	$2,624,029
Audit-Related Fees	$ 432,343	$ 168,968
Tax Fees	$ 345,616	$ 45,743
All Other Fees	$	$
Total	**$ 3,372,142**	**$ 2,838,740**

No other audit firms provided audit services in 2008 or 2007.

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of the Company's annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English into French of the Company's financial statements and

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other documents. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923. Total audit fees for 2007 include payments related to 2006 in the amount of $1,476,300.

Audit-Related Fees

The audit-related fees in 2008 and 2007 were primarily for work performed by Ernst & Young LLP in the provision of miscellaneous accounting advice provided to the Company.

Tax Fees

The majority of tax fees for 2008 related to the finalization of tax credit recoveries.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. The ARC has adopted a policy that prohibits the Company from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories as determined under Sarbanes-Oxley.

Percentage of Services Approved by the ARC

For the year ended December 31, 2008, none of the services described above were approved by the ARC pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

OFF-BALANCE SHEET ARRANGEMENTS

See page 47 of Exhibit 13.3.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 46 of Exhibit 13.3 under the heading "Liquidity and Capital Resources" and page 101 of Exhibit 13.2 under the heading "Commitments".

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing ARC. The members of the ARC are:

William D. Anderson (Chair)
Stephen L. Baum
Timothy W. Faithfull
Michael M. Kanovsky
Gordon S. Lackenbauer
Donna S. Kaufman (ex-officio member)

FORWARD LOOKING INFORMATION

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

Factors that may adversely impact the Corporation's forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which the Corporation operates; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving the Corporation's facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate the Corporation's facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) the Corporation's provision for income taxes; (xvi) legal proceedings involving the Corporation; (xvii) reliance on key personnel; (xviii) labour relations matters; and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in the documents filed herewith under Form 40-F and in other documents and filings made with securities regulatory authorities from time to time.

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

UNDERTAKING

TransAlta Corporation undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

TRANSALTA CORPORATION

/s/ BRIAN BURDEN

Brian Burden
Executive Vice-President and Chief Financial Officer

Dated: March 16, 2009

EXHIBITS

13.1 TransAlta Corporation Annual Information Form for the year ended December 31, 2008.

13.2 Consolidated Audited Financial Statements for the year ended December 31, 2008 (included on pages 66 through 111 of the 2008 TransAlta Annual Report to Shareholders).

13.3 Management's Discussion and Analysis (included on pages 19 through 65 of the 2008 TransAlta Annual Report to Shareholders).

13.4 Reconciliation to United States Generally Accepted Accounting Principles of the 2008 Consolidated Audited Financial Statements.

23.1 Consent of Ernst and Young LLP Chartered Accountants.

31.1 Certification of Chief Executive Officer pursuant to Section 302 and Section 404 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 and Section 404 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of President and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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TRANSALTA CORPORATION

2009 RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 16, 2009

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form (**Annual Information Form**) is given as at or for the year ended December 31, 2008. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward-looking statements. All forward looking statements are based on TransAlta s beliefs as well as assumptions based on information available at the time the assumption was made. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as may , will , believe , expect , anticipate , intend , plan , foresee , potenti 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 TransAlta s actual performance to be materially different from those projected.

Factors that may adversely impact the Corporation s forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which the Corporation operates; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving the Corporation s facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) disruptions in the source of fuels or water required to operate the Corporation s facilities; (viii) trading risks; (ix) fluctuations in the value of foreign currencies and foreign political risks; (x) need for additional financing; (xi) liquidity risk; (xii) structural subordination of securities; (xiii) counterparty credit risk; (xiv) insurance risk; (xv) the Corporation s provision for income taxes; (xvi) legal proceedings involving the Corporation; (xvii) reliance on key personnel and (xviii) labour relations matters and (xix) absence of a public market for certain of the securities offered. The foregoing risk factors, among others, are described in further detail under the heading Risk Factors in this Annual Information Form and in the documents incorporated by reference in this Annual Information Form, including the TransAlta Management s Discussion and Analysis for the year ended December 31, 2008 (the Annual MD&A).

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

DOCUMENTS INCORPORATED BY REFERENCE

TransAlta s Audited Consolidated Financial Statements for the year ended December 31, 2008 and the Annual MD&A are hereby specifically incorporated by reference in this Annual Information Form. Copies of these documents are available on SEDAR at www.sedar.com.

CORPORATE STRUCTURE

Name and Incorporation

TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving the Corporation and TransAlta Utilities Corporation (**TransAlta Utilities** or **TAU**) under the *Canada Business Corporations Act*. The plan of arrangement, which was approved by shareholders on November 26, 1992, resulted in common shareholders of TransAlta Utilities exchanging their common shares for shares of TransAlta on a one-for-one basis. Upon completion of the arrangement, TransAlta Utilities became a wholly-owned subsidiary of TransAlta. On January 1, 2009, TransAlta was issued a Certificate of Amalgamation under the *Canada Business Corporations Act* in connection with the amalgamation of TransAlta Corporation, TransAlta Utilities, TransAlta Energy Corporation (**TransAlta Energy** or **TEC**) and Keephills 3 GP Ltd. The amalgamation was completed as part of a series of transactions involving TransAlta and certain of its subsidiaries and affiliates carried out to reorganize (the **Reorganization**) TransAlta s interest in certain of its assets.

The registered office and principal place of business of TransAlta is at 110 - 12th Avenue S.W., Calgary, Alberta, Canada, T2R 0G7.

Intercorporate Relationships

Effective January 1, 2009, the Corporation completed an internal reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta Corporation and TransAlta Generation Ltd., a wholly-owned subsidiary of TransAlta Corporation. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of the partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the *Canada Business Corporations Act*. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of the wind assets, and some of which are now held indirectly, in the case of the former generation assets and businesses of TAU and TEC.

As of January 1, 2009, the principal subsidiaries of the Corporation and their respective jurisdictions of formation are set out below.

Unless the context otherwise requires, all references to the Corporation and to TransAlta herein refer to TransAlta Corporation and its subsidiaries on a consolidated basis. References to TransAlta Corporation herein refer to TransAlta Corporation, excluding its subsidiaries.

OVERVIEW

TransAlta and its predecessors have been engaged in the production and sale of electric energy since 1909. The Corporation is among Canada s largest non regulated electricity generation and energy marketing companies with an aggregate net ownership interest of 7,976 megawatts (**MW**) of generating capacity[1] operating in facilities having approximately 9,697 MW of aggregate generating capacity. In addition, the Corporation has facilities under construction with a net ownership interest of 456 MW, of an aggregate generating capacity of 681 MW. The Corporation is focused on generating electricity in Canada, the United States and Australia through its diversified portfolio of facilities fuelled by coal, gas, hydroelectric, wind and geothermal resources.

In Canada, the Corporation holds a net ownership interest of 5,661 MW of electrical generating capacity in thermal, gas-fired, wind-powered and hydroelectric facilities, including 4,937 MW in Western Canada, 628 MW in Ontario and 96 MW in New Brunswick.

In the United States, the Corporation s principal facilities include a 1,376 MW thermal facility and a 248 MW gas-fired facility, both located in Centralia, Washington, which supply electricity to the Pacific northwest. The Corporation also holds a 50 per cent interest in CE Generation, LLC (**CE Generation**), through which it has an aggregate net ownership interest of approximately 385 MW of generating capacity in geothermal facilities in California and gas-fired facilities in Texas, Arizona and New York. In addition, the Corporation also has 6 MW of electrical generating capacity through hydroelectric facilities located in Washington and Hawaii.

In Australia, the Corporation has 300 MW of net electrical generating capacity from gas-fired generation facilities.

The Corporation regularly reviews its operations in order to optimize its generating assets and evaluates appropriate growth opportunities. The Corporation has in the past and may in the future make changes and additions to its fleet of coal, gas, hydro, wind and geothermal fuelled facilities.

The Corporation is organized into two business segments: Generation and Commercial Operations and Development. The Generation group is responsible for constructing, operating and maintaining electricity generation facilities. The Commercial Operations and Development group is responsible for managing the sale of production, purchasing natural gas, transmission capacity and market risks associated with the Corporation s generation assets and for non asset backed trading activities. Both segments are supported by a corporate group that provides finance, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government relations, information technology, human resources, internal audit, and other administrative support.

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1 TransAlta measures capacity as the net maximum capacity that a unit can sustain over a period of time, which is consistent with industry standards. All capacity amounts are as of the date of this Annual Information Form and represent capacity owned and operated by the Corporation unless otherwise indicated.

GENERAL DEVELOPMENT OF THE BUSINESS

The significant events and conditions affecting TransAlta s business during the three most recently completed financial years are summarized below. Certain of these events and conditions are discussed in greater detail under the heading Business of TransAlta in this Annual Information Form.

Recent Developments

- On February 10, 2009, the Corporation reported that the 406 MW Sundance 4 facility had experienced an unplanned outage in December 2008 relating to the failure of an induced draft fan. At the time, the unit was derated to approximately 205 MW. The repair of the fan components by the original equipment manufacturer took longer than planned and, therefore, Unit 4 did not return to full service until February 23, 2009. As a result of the extended derate, first quarter production was reduced by 328GWh and net income declined by $17 million. The Corporation has given notice of a High Impact Low Probability Event to the PPA Buyer and the Balancing Pool which, if successful, will protect the Corporation from the financial loss and related penalties. The available penalties that the Corporation expects to recover in net income are anticipated to be $14 million.

- On January 29, 2009, the Board of Directors of the Corporation declared a quarterly dividend of $0.29 per common share, payable April 1, 2009 to holders of record on March 1, 2009. This represents a $0.02 per share increase in the quarterly dividend, yielding on an annualized basis a dividend of $1.16 per share.

- On January 29, 2009, the Corporation announced that it will be proceeding with the addition of two 23 MW efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded to 406 MW and are expected to be operational by the end of 2011 and 2012, respectively. The total capital cost of the projects is estimated at $68 million.

- Effective January 1, 2009, the Corporation completed an internal reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta and TransAlta Generation Ltd., a wholly-owned subsidiary of TransAlta. TransAlta Generation Partnership is managed by TransAlta pursuant to the terms of the partnership agreement and a management services agreement. Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the *Canada Business Corporations Act*. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of the wind assets, and some of which are now held indirectly, in the case of the former generation assets and businesses of TAU and TEC.

Year Ended December 31, 2008

- On December 31, 2008, the Corporation announced that the 96 MW, $170 million Kent Hills Wind Farm had begun commercial operation. The wind farm consists of 32 Vestas V90, 3MW wind turbines. The capacity from this project is sold under a power purchase agreement with New Brunswick Power Distribution and Customer Service Corporation (**New Brunswick Power**).

- On October 8, 2008, the Corporation announced the completion of the sale of its Mexican businesses to Intergen Global Ventures B.V. II for a sale price of US$303.5 million. The sale included the 252 MW gas/diesel combined cycle gas plant in Campeche, a 259 MW combined cycle gas plant in Chihuahua and all associated commercial arrangements.

- On May 27, 2008, the Corporation announced that, commencing in 2009, it would be constructing another 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital cost for this expansion of the Summerview wind power project is expected to be $123 million. The capacity from this project is expected to be sold on the Alberta Power Pool.

- On May 5, 2008, the Corporation announced that it had received regulatory approval from the Toronto Stock Exchange (**TSX**) for the continuation of its normal course issuer bid (**NCIB**) program. Under the NCIB program, the Corporation has approval to purchase, for cancellation, up to 19.9 million of its common shares, representing 10 per cent of its public float as of April 23, 2008.

- On April 21, 2008, the Corporation announced a 53 MW efficiency uprate at Unit 5 of its Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009.

- On April 3, 2008, TransAlta announced a partnership with Alstom LLC to develop a one million tonne/year carbon capture and storage project at one of TransAlta s coal-fired power stations in Alberta. This project has been shortlisted by the Alberta Government for contributory funding as part of the province s $2 billion carbon capture and storage (**CCS**) program, with a decision expected by June 30, 2009.

- On February 20, 2008, the Corporation announced it had signed a purchase and sale agreement with Intergen Global Ventures B.V. pursuant to which Intergen agreed to pay the Corporation US$303.5 million in cash for its Mexican assets.

- On February 13, 2008, the Corporation announced that, commencing in 2009, it would be constructing a 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital costs for this Blue Trail wind power project is expected to be $115 million. The capacity from this project is expected to be sold on the Alberta Power Pool.

- On February 1, 2008, the Board of Directors of the Corporation declared a quarterly dividend of $0.27 per common share, payable April 1, 2008 to holders of record on March 1, 2008. This represents a $0.02 per share increase in the quarterly dividend, yielding on an annualized basis a dividend of $1.08 per share.

Year Ended December 31, 2007

- During the third quarter, the Corporation completed an uprate on the Sundance Unit 4 facility. A final measurement took place in the fourth quarter of 2007 and the generating capacity added as a result of this uprate was 53 MW.

- On September 11, 2007, the Corporation announced it had received regulatory approval to increase the number of shares it may purchase under its NCIB program. As a result, the Corporation was authorized to purchase for cancellation up to 20.2 million shares or approximately 10 per cent of the 202 million common shares issued and outstanding as of April 23, 2007.

- On July 17, 2007, the Corporation amended the power purchase agreement with New Brunswick Power to increase capacity at its Kent Hills wind power facility from 75 MW to 96 MW. As a result, total capital costs for the Kent Hills project will also increase by $40 million, from $130 million to $170 million. The Corporation also signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., to acquire its Fairfield Hill wind power site, including an option to develop the site at a future date.

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

- On February 26, 2007, the Corporation and EPCOR Power Development Corporation (**EPCOR**) announced that they were proceeding with building the 450 MW Keephills 3 power project located approximately 70 kilometres west of Edmonton, Alberta. The capital cost for the project, including mine capital, is expected to be approximately $1.6 billion and is expected to be completed at the end of the first quarter of 2011. Through the Keephills 3 Limited Partnership (**K3LP**), an affiliate of the Corporation, TransAlta and EPCOR will be equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and EPCOR responsible for the construction. Upon completion, it is expected that TransAlta will operate the facility and EPCOR and TransAlta will independently dispatch and market their share of the unit s electrical output. The project has received approval from the Alberta Energy and Utilities Board and from Alberta Environment.

- On January 19, 2007, the Corporation announced that it had been awarded a 25-year Power Purchase Agreement (**PPA**) to provide 75 MW of wind power to New Brunswick Power. Under the agreement, TransAlta will construct, own and operate a wind power facility in New Brunswick. The capital cost of the project is estimated to be $130 million. The project is subject to regulatory and environmental approvals and is expected to begin commercial operations by the end of 2008. Natural Forces Technologies Inc., an Atlantic Canada based wind developer, is TransAlta s co-development partner in this project.

- On January 2, 2007, the Corporation redeemed, at par, all of its outstanding 7.75 per cent preferred securities, with an outstanding principal amount of $175 million.

Year ended December 31, 2006

- On December 18, 2006, TransAlta Utilities assigned its rights in the development agreement it held with EPCOR, governing the joint development of the Keephills 3 power project, to K3LP. K3LP subsequently sold a 50 per cent undivided interest in the Keephills 3 power project to the EPCOR Power Development (K3) Limited Partnership and has entered into a joint venture agreement governing the continued development of the Keephills 3 power project. In the event the Keephills 3 power project proceeds to operation, it is anticipated that TransAlta will be the operator of the project pursuant to an operations and maintenance agreement and coal supply agreement.

- On November 27, 2006, TransAlta announced it would immediately stop mining operations at its Centralia, Washington coal-mine. TransAlta also announced that it had entered into agreements to purchase and transport coal from the Powder River Basin to fuel TransAlta s Centralia thermal facility.

- On November 17, 2006, TransAlta Utilities entered into a settlement agreement with Canadian National Railway Company for a portion of outstanding claims for lost margin and incremental expenses relating to the train derailment and resulting oil spill into Lake Wabamun in 2005. The terms of the settlement are subject to a confidentiality agreement and cannot be disclosed.

- On February 17, 2006, a wholly-owned subsidiary of TransAlta, together with a subsidiary of Mid-American Energy Company (**Mid-American**), entered into an agreement to purchase a 10 MW hydro facility in Hawaii to be held directly by the Wailuku Holding Company LLC, a company jointly and equally owned by TransAlta and Mid-American.

- On February 15, 2006, TransAlta announced it had signed a five-year agreement with the Ontario Power Authority (**OPA**) for the supply of electricity from TransAlta s Sarnia Regional Cogeneration Power Plant. Under the terms of the agreement, Transalta will be available to supply an average of 400 MW of electricity to the Ontario electricity market. The supply contract is effective until December 31, 2010.

- On February 1, 2006, TransAlta Utilities entered into a development agreement with EPCOR to jointly pursue the Keephills 3 power project. Keephills 3 is a proposed 450 MW facility adjacent to TransAlta s existing Keephills facility, approximately 70 kilometres west of Edmonton, Alberta.

BUSINESS OF TRANSALTA

Generation Business Segment

The following table summarizes the Corporation s generation facilities which are operating, under construction or under development, as at January 31, 2009:

Region	**Facility**	**Capacity (MW)**	**Ownership (%)**	**Net Capacity Ownership Interest**	**Fuel**	**Revenue Source**	**Contract Expiry Date**
Western Canada (28 Facilities)	Sundance (1)	2,126	100	2,126	Coal	Alberta PPA / Merchant (2)	2017, 2020
	Keephills (3)	812	100	812	Coal	Alberta PPA	2020
	Sheerness	780	25	195	Coal	Alberta PPA	2020
	Wabamun	279	100	279	Coal	Merchant	-
	Genesee 3	450	50	225	Coal	Merchant	-
	Keephills 3 (4)	450	50	225	Coal	Merchant	-
	Fort Saskatchewan	118	30	35	Gas	Long-term contract (**LTC**)	2019
	Meridian	220	25	55	Gas	LTC	2024
	Poplar Creek	356	100	356	Gas	LTC/Merchant	2024
	Hydro assets (5)	801	100	801	Hydro	Alberta PPA	2013-2020
	Castle River (6)	44	100	44	Wind	LTC/Merchant	2011
	McBride Lake	75	50	38	Wind	LTC	2024
	Summerview 1 (7)	70	100	70	Wind	Merchant	-
	Blue Trail (4)	66	100	66	Wind	Merchant	-
	Summerview 2 (4)	66	100	66	Wind	Merchant	-
	Total Western Canada	**6,713**		**5,393**			
Eastern Canada (5 Facilities)	Mississauga	108	50	54	Gas	LTC	2017
	Ottawa	68	50	34	Gas	LTC	2012
	Windsor	68	50	34	Gas	LTC/Merchant	2016
	Sarnia (8)	506	100	506	Gas	LTC/Merchant	2022
	Kent Hills	96	100	96	Wind	PPA	2033
	Total Eastern Canada	**846**		**724**			
United States (17 Facilities)	Centralia (9)	1,376	100	1,376	Coal	Merchant	-
	Centralia Gas	248	100	248	Gas	Merchant	-
	Power Resource	212	50	106	Gas	Merchant	-
	Saranac	240	37.5	90	Gas	LTC	2009
	Yuma	50	50	25	Gas	LTC	2024
	Imperial Valley Geothermal Facilities (10)	327	50	164	Geothermal	LTC/Merchant	2016-2029
	Skookumchuk	1	100	1	Hydro	-	-
	Wailuku	10	50	5	Hydro	LTC	2023
	Total US	**2,464**		**2,015**			
Australia (5 Facilities)	Parkeston	110	50	55	Gas	LTC	2016
	Southern Cross (11)	245	100	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			
Total		**10,378**		**8,432**			

Notes:

(1) Includes a 53 MW uprate expected to be commercial in 2009.

(2) Merchant capacity refers to 53 MW and 44 MW uprates on units 4 and 6, respectively.

(3) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively.

(4) These facilities are currently under development.

(5) Comprised of 13 facilities.

(6) Includes 7 individual turbines at other locations.

(7) Comprised of 2 facilities.

(8) Sarnia s net maximum capacity (**NMC**) has been adjusted from 575 MW due to decommissioning of equipment at the facility.

(9) Centralia Thermal s NMC has been reduced from 1,404 MW to reflect a lower plant output as a result of its conversion to burning Powder River Basin coal.

(10) Comprised of 10 facilities.

(11) Comprised of 4 facilities.

Canada: Alberta

Thermal facilities

The following table summarizes the Corporation s western Canadian thermal generation facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Wabamun (1)	Wabamun Unit No. 4	279	100	1968
Sundance	Sundance Unit No. 1	280	100	1970
	Sundance Unit No. 2	280	100	1973
	Sundance Unit No. 3	353	100	1976
	Sundance Unit No. 4	406	100	1977
	Sundance Unit No. 5 (2)	406	100	1978
	Sundance Unit No. 6	401	100	1980

Keephills	Keephills Unit No. 1 (3)	406	100	1983
	Keephills Unit No. 2 (3)	406	100	1984
	Keephills Unit No. 3 (4)	450	50	2011
Sheerness	Sheerness Unit No. 1	390	25	1986
	Sheerness Unit No. 2	390	25	1990
Genesee	Genesee 3	450	50	2005
Total		**4,897**		

Notes:

(1) Wabamun unit 4 is expected to be removed from service upon the expiry of its license in 2010.

(2) Includes a 53 MW uprate expected to be commercial in 2009.

(3) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively.

(4) This facility is currently under development.

The Keephills, Sundance and Wabamun facilities (the **Alberta thermal plants**) are located approximately 70 kilometres west of Edmonton, Alberta and are owned by TransAlta. The Sheerness facility is jointly owned by TransAlta Cogeneration, L.P. (**TA Cogen**), an Ontario limited partnership, and ATCO Power (2000) Ltd. (**ATCO Power**). The Genesee facility is jointly owned by TransAlta and EPCOR. TransAlta s thermal plants are generally base load plants, meaning that they are expected to operate for long periods of time at or near their rated capacity. Availability is an important measure of the economic success of a thermal plant. The weighted equivalent availability factor for the Alberta thermal plants in 2008 was 82.9 per cent compared with 87.1 per cent in 2007 and 88.7 per cent in 2006. For the Sheerness facility, the weighted equivalent availability factor was 94.1 per cent in 2008 compared to 94.4 per cent in 2007 and 92.2 per cent in 2006. For the Genesee 3 facility, the weighted equivalent availability factor was 78.2 per cent in 2008 compared to 92.9 per cent in 2007 and 96.9 per cent in 2006.

Fuel requirements for TransAlta s thermal power facilities are supplied by surface strip coal-mines located in close proximity to the facilities. TransAlta owns two surface mines in Alberta that supply coal to its Alberta thermal plants. The Whitewood mine supplies the Wabamun plant and the Highvale mine supplies the Sundance and Keephills facilities. TransAlta estimates that the recoverable coal reserves contained in these mines are expected to be sufficient to supply the anticipated requirements for the life of these facilities including running post PPA expiry and plant expansion.

Coal for the Sheerness facility is provided from the adjacent Sheerness mine. The coal reserves of the mine are owned, leased or controlled jointly by TA Cogen, ATCO Power and Prairie Mines & Royalties Limited (**PMRL**).

TA Cogen and ATCO Power have entered into coal supply agreements with PMRL, which operates the mine, to supply coal until 2026.

Coal for the Genesee 3 facility is provided from the adjacent Genesee mine. The coal reserves of the mine are owned, leased or controlled jointly by PMRL and EPCOR. The Corporation has entered into coal supply agreements with PMRL, which operates the mine, to supply coal for the life of the facility.

In February 2001, the Corporation announced a proposal for a 900 MW expansion at its Keephills facility. Although the Corporation received regulatory approval to proceed with the expansion, an application was made, in December 2004, to the AEUB to amend its 900 MW permit to allow for the construction of a smaller 450 MW facility using improved technology.

On February 1, 2006, the Corporation entered into a development agreement with EPCOR to jointly pursue the 450 MW Keephills 3 power project. On December 18, 2006, the Corporation assigned its rights in the development agreement which it held with EPCOR for the joint development of the Keephills 3 power project to K3LP, an affiliate of the Corporation. K3LP subsequently sold a 50 per cent undivided interest in the Keephills 3 power project to the EPCOR Power Development (K3) Limited Partnership and has entered into a joint venture agreement governing the continued development of the Keephills 3 power project. The project received approval from the Alberta Energy and Utilities Board and from Alberta Environment.

On February 26, 2007, the Corporation and EPCOR commenced construction of the net 450 MW Keephills 3 power project. The capital cost for the project, including mine capital, is expected to be approximately $1.6 billion and is expected to be completed at the end of the first quarter of 2011. Through K3LP, TransAlta and EPCOR will be equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and EPCOR responsible for construction. Upon completion, it is expected that TransAlta will operate the facility and EPCOR and TransAlta will independently dispatch and market their share of the unit s electrical output. The Corporation will also provide coal to the facility through the Highvale mine. On January 29, 2009, the Corporation s estimate of total costs for Keephills 3 increased by $73 million, due to higher material and labour costs, for a total projected cost of $1.7 billion. The Corporation continues to monitor the costs and will look for opportunities to reduce the cost increases.

Gas fired facilities

The following table summarizes the Corporation s western Canadian gas fired generation facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Lloydminster, SK	Meridian	220	25	1999
Fort McMurray, AB	Poplar Creek	356	100	2001

Fort Saskatchewan, AB	Fort Saskatchewan	118	30	1999
Total		**694**		

The Corporation s interests in the Meridian and Fort Saskatchewan facilities are held through TA Cogen. See TA Cogen .

The Meridian plant is located in Lloydminster, Saskatchewan and is owned by TA Cogen and Husky Oil Operations Limited. The Meridian plant sells electricity to Saskatchewan Power Corporation, a Crown corporation owned by the Province of Saskatchewan, and steam to a heavy oil upgrader in Lloydminster, Saskatchewan.

The Poplar Creek plant is located in Fort McMurray, Alberta and is owned by the Corporation. This 356 MW cogeneration plant became fully operational in the first quarter of 2001 and delivers approximately 200 MW of electricity and steam to Suncor Energy Inc. (**Suncor**). Any surplus power not used by Suncor is available for sale by the Corporation to other parties, in which case Suncor is entitled to a share of that revenue, under certain conditions.

The Fort Saskatchewan plant is located in Fort Saskatchewan, Alberta and is owned by TA Cogen and Air Liquide Canada Inc. The 118 MW Fort Saskatchewan gas fired combined cycle cogeneration plant in Alberta provides electricity and steam to Dow Chemical Canada Inc.

Hydroelectric facilities

The following table summarizes the Corporation s western Canadian hydroelectric facilities:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Bow River System	Horseshoe	14	100	1911
	Kananaskis	19	100	1913, 1951
	Ghost	51	100	1929, 1954
	Cascade	36	100	1942, 1957
	Barrier	13	100	1947
	Bearspaw	17	100	1953, 1954
	Pocaterra	15	100	1955
	Interlakes	5	100	1955
	Spray	103	100	1951, 1960
	Three Sisters	3	100	1951
	Rundle	50	100	1951, 1960
			100	
North Saskatchewan River System	Brazeau	355	100	1965, 1967
	Bighorn	120	100	1972
Total		**801**		

The Corporation s hydroelectric facilities are primarily peaking plants, meaning they are generally only operated during times of peak demand.

Wind Generation Facilities

The following table summarizes the Corporation s wind generation facilities:

Location	**Plant**	**Commissioning Dates**

		Capacity (MW)	Ownership (%)	
Fort MacLeod	McBride Lake	75	50	2003
Pincher Creek	Castle River and Other	44	100	1997 2001
Pincher Creek	Summerview 1	70	100	2004
New Brunswick	Kent Hills	96	100	2008
Fort Macleod	Blue Trail (1)	66	100	2009
Pincher Creek	Summerview 2 (1)	66	100	2010
Total		**417**		

Note:

(1) Facility under development reflects expected capacity and commissioning date.

The Corporation owns and operates approximately 248 MW of net capacity (excluding facilities under development) and operates approximately 285 MW of capacity primarily in three wind farms in southwestern Alberta and one in New Brunswick.

Castle River is a 40 MW facility comprised of 59 Vestas V47 (660 kW) turbines and 1 Vestas V44 (600 kW) turbine located at Pincher Creek, Alberta. The facility is 71 per cent contracted primarily to ENMAX Energy Corp.

(**ENMAX**) and is the sole Green Energy® provider to the City of Calgary s Ride the Wind Light Rail Transit program. The Corporation also owns and operates seven additional turbines totalling 4 MW located individually in the Pincher Creek, Fort Macleod and Hillspring areas of southwestern Alberta.

McBride Lake is a 75 MW facility comprised of 114 Vestas V47 (660 kW) turbines located at Fort MacLeod, Alberta. It was constructed by the Corporation and has been producing electricity since the third quarter of 2003. McBride Lake is operated by the Corporation and is owned by the Corporation and ENMAX Green Power Inc. The output from the facility is 100 per cent contracted in the form of a 20 year PPA with ENMAX. The Corporation is also entitled to receive Wind Power Production Incentive (**WPPI**) payments from the federal government at $12/MWh in respect of the McBride Lake facility until 2013.

On October 13, 2004, TransAlta announced the commencement of commercial operations at its $100 million Summerview 68 MW wind farm located approximately 15 kilometres northeast of Pincher Creek, Alberta. The Summerview facility, which comprises 38 1.8 MW turbines, together with an existing 1.8 MW turbine in the area, brings the total wind generation capacity at that location to 70 MW. The Summerview wind farm is a merchant facility but is entitled to receive WPPI payments from the Federal Government at $10/MWh until 2014.

On January 19, 2007, the Corporation announced that it had been awarded a 25 year PPA to deliver 75 MW of wind power to New Brunswick Power. On July 17, 2007, the Corporation announced it had amended its PPA with New Brunswick Power from 75 MW to 96 MW bringing the total capital cost for the project to an estimated $170 million. The project was completed by the end of 2008. Natural Forces Technologies Inc. (**Natural Forces**), an Atlantic Canada based wind developer, is TransAlta s co-development partner in this project and Natural Forces has an option to purchase up to 17 per cent of the Kent Hills project within 180 days of its completion.

On February 13, 2008, the Corporation announced that, commencing in 2009, it would be constructing a 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital cost for this Blue Trail wind power project is expected to be $115 million. The capacity from this project is expected to be sold on the Alberta Power Pool. The Blue Trail wind farm is entitled to receive payments from Natural Resources Canada (**NRCan**), a division of the federal government, through the eco Energy for Renewable Power (**eERP**) program.

On May 27, 2008, the Corporation announced that, commencing in 2009, it would be constructing another 66 MW wind generation facility in southern Alberta, consisting of 22 Vestas V90 3 MW wind turbines. The total capital costs for this expansion of the Summerview 2 wind power project is expected to be $123 million. The capacity from this project is expected to be sold on the Alberta Power Pool. With this announcement, existing and planned wind generation facilities owned and operated by the Corporation total 419 MW. The Summerview 2 wind farm expansion is entitled to receive payments from NRCan through the eERP program.

All of the electricity generated and sold by the Corporation s wind division is from generation facilities that are EcoLogo certified. The Corporation is an EcoLogo certified distributor of Alternative Source Electricity through Environment Canada s Environmental Choice program. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards. The Corporation s wind facilities constructed after April 2001, also qualify for the Green E and Green Leaf certifications.

Alberta PPAs

All of the Corporation s Alberta thermal and hydroelectric facilities, other than the Wabamun, Genesee 3 facilities, and uprated capacity, operate under Alberta PPAs. The Alberta PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each thermal plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which electricity is to be supplied. The Corporation bears the risk or retains the benefit of volume variances (except for those arising from events considered to be force majeure, in the case of the thermal plants) and any change in costs (unless due to a change in law) required to maintain and operate the facilities.

Under the Alberta PPAs, for the formerly regulated thermal facilities, the Corporation is exposed to electricity price risk if availability declines below contracted levels (other than as a result of outages caused by an event of force majeure). In such circumstances, the Corporation must pay a penalty for the lost availability based upon a price equal to the 30 day rolling average of Alberta s market electricity prices. This rolling average provision attempts to mitigate price spikes that can occur as a result of sudden outages. The Corporation attempts to further mitigate this exposure by maintaining contracted and uncontracted capacity in the market, through operating and maintenance practices, and through hedging activities.

The Corporation s hydroelectric facilities are not contracted on a facility-by-facility basis; rather, facilities are aggregated in a single Alberta PPA which provides for financial obligations for energy and ancillary services based on hourly targets. These targeted amounts are met by the Corporation through physical delivery or third party purchases.

The Corporation s compensation under the Alberta PPAs is based on a pricing formula which replaced the cost of service regime that applied previously under utility regulation. Key elements of the pricing formula are the amount of common equity deemed to form part of the capital structure, the amount of risk premium attributable to deemed common equity and a recovery of fixed and variable costs. Common equity is deemed to be 45 per cent of total capital and the return on equity is set annually at a 4.5 per cent premium over the rate on a 10-year Government of Canada Bond.

The pricing formula includes a provision for site restoration costs of the thermal generating plants for the whole term of the PPA. Until 2017, if the costs recovered are insufficient, then the Corporation can apply to the Balancing Pool to recover the incremental portion. The Alberta PPAs include, as part of the capacity payment for hydroelectric operations, an amount for decommissioning.

The expiry dates for the Corporation s Alberta PPAs, range from 2013 to 2020. With the expiry of the PPA at the Wabamun facility, the Corporation procured an extension of the license to operate Unit four of the Wabamun facility until March 31, 2010. The Corporation holds various licenses from Alberta Environment and the AEUB to operate its other facilities, most of which are renewed every few years. The Corporation is evaluating the economics of running assets post-PPA expiry. Upon the expiry of the PPAs and subject to procuring an extension of the licenses, if required, the Corporation will then be able to sell its electricity to the Alberta Power Pool and to third party purchasers through direct sales agreements. The Corporation is currently selling most of its electricity from the Wabamun facility on the spot market.

The Alberta PPAs (together with legislation which applies thereto) permit the Balancing Pool, an entity established by the Government of Alberta, directly or indirectly as successor to the power purchaser under the Alberta PPAs, to terminate the Alberta PPAs in certain circumstances. These termination provisions are similar to those found in some PPAs entered into by government related power purchasers. The Corporation will be entitled to receive a lump sum payment in connection with any such termination, other than a termination resulting from the Corporation s default and will thereafter be able to sell the output from any affected facilities for its own account.

Canada: Ontario

The Corporation s Ontario generating facilities are summarized in the following table:

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**
Sarnia	Sarnia	506	100	2003
Ottawa	Ottawa	68	50	1992
Mississauga	Mississauga	108	50	1992

Location	**Plant**	**Capacity (MW)**	**Ownership (%)**	**Commissioning Dates**

Windsor	Windsor	68	50	1996
Total		**750**		

The Sarnia facility is a combined cycle cogeneration facility which is owned by the Corporation. The Corporation acquired 135 MW of electric generation capacity in 2002, and in March 2003 the Corporation acquired the remaining 440 MW of capacity. On January 1, 2009, the Corporation applied, and subsequently received approval, to decommission a 69 MW turbine at Sarnia. The 506 MW facility provides steam and electricity to nearby facilities owned by Dow Chemical Canada Inc., Lanxess (formerly Bayer Inc.), Nova Chemicals (Canada) Ltd. and Suncor Energy Products Inc. On February 15, 2006, TransAlta announced that it had signed a five-year agreement with the OPA for production at its Sarnia facility. Under the terms of the contract, TransAlta will be available to supply an average of 400 MW of electricity to the Ontario electricity market. The supply contract is effective until December 31, 2010. On December 24, 2008, the Minister of Energy and Infrastructure directed the OPA to seek contracts with certain energy providers in Ontario, namely those listed in a December 14, 2005 Direction which includes Sarnia, for the supply of clean and efficient electricity generation. The OPA is not required to enter a new contract with the energy provider where an agreement cannot be reached as to what constitutes a reasonable cost to Ontario electricity consumers and a reasonable balancing of risk and reward.

The Ottawa plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 68 MW of electrical energy. This capacity is sold under a long-term contract with the Ontario Electricity Financial Corporation (**OEFC**), an agency of the Province of Ontario. This agreement expires in 2012. The Ottawa plant also provides thermal energy to the member hospitals and treatment centers of the Ottawa Health Sciences Centre, National Defence Medical Centre and the Perley and Rideau Veterans Health Centre.

The Mississauga plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 108 MW of electrical energy. This capacity is contracted under a long-term contract with the OEFC which expires in 2017. The Mississauga Plant provided cogeneration services to Boeing Canada Inc. (**Boeing**) until July 2005 at which time Boeing exercised its right under the cogeneration services agreement to no longer take and pay for cogeneration services due to the recent closure of its manufacturing facility. Boeing remains entitled to any steam credits based on the total plant electricity generation revenue. On or prior to each of January 1, 2013, 2018 and 2023, Boeing may give notice of its intention to continue to purchase, or discontinue, cogeneration services. In addition, on those same dates, Boeing has the option to require the removal of the Mississauga Plant from the leased lands or purchase the Mississauga Plant at its net salvage value.

The Windsor plant is owned by TA Cogen. It is a combined cycle cogeneration facility designed to produce 68 MW of electrical energy. Currently, 50 MW of the capacity is sold under a long-term contract to the OEFC. This agreement expires in 2016. The Windsor plant also provides thermal energy to Chrysler Canada Inc. s minivan assembly facility in Windsor. In 2003, an agreement was reached with the OEFC to sell the remaining 18 MW to the Ontario power market when it is economic to do so.

United States

The Corporation s generation facilities in the United States are summarized in the following table:

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates

Washington	Centralia Coal No. 1	688	100	1971
	Centralia Coal No. 2	688	100	1971
	Centralia Gas	248	100	2002
	Skookumchuk	1	100	1970

Location	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates

New York	Saranac	240	37.5	1994
California	Vulcan	34	50	1986
	Del Ranch	38	50	1989
	Elmore	38	50	1989
	Leathers	38	50	1990
	CE Turbo	10	50	2000
	Salton Sea I	10	50	1987
	Salton Sea II	20	50	1990
	Salton Sea III	50	50	1989
	Salton Sea IV	40	50	1996
	Salton Sea V	49	50	2000
Texas	Power Resources	212	50	1988
Arizona	Yuma	50	50	1994
Hawaii	Wailuku	10	50	1993
Total		**2,464**		

Centralia

The Corporation owns a two unit 1,376 MW thermal facility and a 248 MW gas-fired facility in Centralia, Washington, located south of Seattle. The Corporation also owns a 1 MW hydro-electric generating facility and related assets on the Skookumchuk River near Centralia, which facilities are used to provide reliable water supply to TransAlta s other generation facilities at Centralia. TransAlta also owns a coal-mine adjacent to the Centralia facility, however, it stopped all mining operations at the mine in late 2006.

The Corporation has entered into a number of medium to long-term energy sales agreements from the Centralia facility. The Corporation also sells electricity from the Centralia facility into the Western Electricity Coordinating Council and, in particular, on the spot market in the U.S. Pacific Northwest energy market. The Corporation s strategy is to balance contracted and non contracted sales of electricity to manage production and price risk.

The Corporation stopped mining operations at its Centralia coal-mine on November 27, 2006. Prior to that date, the Centralia mine produced approximately five to six million tons of coal annually, or approximately 70 to 85 per cent of the Centralia plant s annual coal requirements. Although the Corporation estimates that certain coal reserves remain to be extracted, the Corporation has not yet received permits for, nor developed the new area, from which this coal could be produced. The Corporation has entered into contracts to purchase and transport coal from the Powder River Basin in Montana and Wyoming to fuel its facility until such time, if any, as it is economic to pursue the extraction of coal at its Centralia mine.

CE Generation

On January 29, 2003, TransAlta announced the completion of the acquisition from El Paso Corporation (**El Paso**) of a 50 per cent interest in CE Generation, for total consideration of approximately US$240 million, which included approximately US$35 million for working capital. The CE Generation acquisition included the right to a 50 per cent interest in Salton Sea VI, a geothermal project, in the Imperial Valley, California. While there is still future development potential for CE Generation in the Imperial Valley, the Salton Sea VI project that was being pursued when TransAlta acquired its interest in CE Generation was never developed.

CE Generation, through its subsidiaries, is primarily engaged in the development, ownership and operation of independent power production facilities in the United States using geothermal and natural gas resources. CE Generation holds a net ownership interest of approximately 385 MW in 13 facilities, having an aggregate operating capacity of 829 MW, including 327 MW of geothermal generation in California and 502 MW of gas fired cogeneration in New York, Texas and Arizona.

CE Generation affiliates currently operate 10 geothermal facilities in Imperial Valley, California. Each of the geothermal facilities sells electricity pursuant to independent, long term contracts.

CE Generation affiliates currently operate three natural gas fired facilities in Texas, Arizona and New York State, having an aggregate generation capacity of 502 MW. The Arizona facility sells its output pursuant to long-term contracts while the Texas facility has contracted a tolling agreement for capacity, which expires at the end of 2009. The New York facility sells its output pursuant to long-term contracts until mid-2009, after which point its capacity will be sold on the spot market. The intent is to re-contract both the New York facility and the Texas facility under a tolling agreement for capacity.

Wailuku

On February 17, 2006, a subsidiary of TransAlta, together with a subsidiary of Mid-American entered into an arrangement to purchase a 10 MW hydro facility in Hawaii to be held directly by the Wailuku Holding Company LLC. Each of TransAlta and Mid American hold a 50 per cent interest in the facility. The facility sells electricity pursuant to the terms of a 30 year long-term contract with the Hawaii Electricity Light Company.

Australia

The Corporation holds interests in Western Australia consisting of the 110 MW Parkeston generation facility through a 50/50 joint venture with NP Kalgoorlie Pty Ltd, a subsidiary of Newmont Australia Limited, and the 245 MW Southern Cross Energy gas and diesel generation facilities. Most of TransAlta s generation supplies two large mining companies through long-term capacity contracts and the remaining amount of surplus energy and capacity is sold into Australia s Wholesale Electricity Market which was introduced in Western Australia in late 2006.

TA Cogen

The Corporation s interest in the 220 MW Meridian natural gas fired generation facility in Saskatchewan, the 780 MW Sheerness thermal generation facility, the 118 MW Fort Saskatchewan gas fired cogeneration facility in Alberta, and the Mississauga, Ottawa and Windsor Essex facilities in Ontario, are held through TA Cogen, an Ontario limited partnership owned 50.01 per cent by subsidiaries of TransAlta and 49.99 per cent by Stanley Power Inc., a subsidiary of Cheung Kong Infrastructure Holdings Limited.

Commercial Operations and Development

The Commercial Operations Development group provides a number of strategic functions to the Corporation, including the following:

- Gathering and assessing market intelligence, enabling management to more effectively engage in strategic planning and decision making for the Corporation. This includes identifying and ranking markets which are the most attractive to enter, and developing strategies and plans to effectively compete in each market where the Corporation operates;

- Identifying specific opportunities to develop, acquire, or divest of generation assets in markets where the Corporation is operating or growing and completing the business arrangements so the Corporation can either make investment or divesture decisions;

- Negotiating and entering into contractual agreements with customers for the sale of output from the Corporation s generating assets, including electricity, steam or other energy related commodities;

- Scheduling physical deliveries of natural gas supplies used to generate electricity and the electrical generation outputs from each asset to meet contractual obligations while managing the physical and financial risks associated with the generation and transmission of electrical energy, including during those periods of unplanned outages;

- Increasing the value of electricity output and fuel inputs from each generating asset through a variety of regional portfolio optimization strategies in both the current year and over the long-term; and

- Recommending optimum maintenance schedules and operating levels according to current and anticipated market conditions that will maximize earnings from each of the generation assets.

Beyond these functions, the Commercial Operations Development group derives additional revenue and earnings from the wholesale trading of electricity and other energy related commodities and derivatives.

The group seeks to manage and limit risk exposures from both financial and physical positions, as well as counterparty risks. The key risk control activities of the Commercial Operations Development group, in conjunction with other functions of the Corporation, include credit review approval and reporting, risk measurement monitoring and reporting, validation of transactions, and trading portfolio valuation monitoring and reporting.

The Corporation uses mark-to-market valuation and the application of a value at risk (**VAR**) determination for risk control practices for its trading portfolios. This approach is a measure of assessing the potential trading losses that the Corporation could experience over a given time, due to fluctuations in energy prices in each market. The Corporation s policy is to actively manage and limit the group s aggregate VAR exposure within board approved limits.

Competitive Environment

TransAlta is the largest generator of electricity in Alberta, measured by capacity, and has a significant portfolio of generation assets in the Pacific Northwest and western U.S. The Corporation also owns and operates generating assets in eastern Canada and Australia.

The Corporation expects continued long-term growth of electricity demand in its core markets although short-term growth rates may be significantly reduced in the current economic environment. In addition to increased demand, many of the markets in which TransAlta participates have established renewable portfolio targets or standards that require new renewable power investments.

As part of its balanced approach to capital allocation which includes returning capital to shareholders through dividends and share buybacks, TransAlta also has plans for investing in new capacity in its core markets where opportunities exist for renewable and cogeneration assets.

Alberta is Canada s fourth largest province by population with approximately 3.6 million residents representing approximately 11 per cent of Canada s total population. Alberta consumed approximately 70,000 GWh of electricity in 2008. As at December 31, 2008, the aggregate installed capacity of generating facilities in Alberta was approximately 12,300 MW.

Electrical utilities in the U.S. Pacific Northwest are organized into the Western Electricity Coordinating Council (WECC). The WECC is the largest geographically of the ten regions in the North American Electric Reliability Council and is divided into four sub regions, of which Region 1 includes British Columbia, Alberta, Washington, Oregon, Idaho, Montana, Utah, Western Wyoming and Northern Nevada. This sub region is referred to as the Northwest Power Pool (NWPP). The WECC estimates that approximately 369,000 GWh of electricity was consumed in the NWPP in 2008. The WECC also reported an estimated aggregate electrical generating capacity of approximately 85,000 MW in the NWPP for the year ending 2008.

Ontario is Canada s largest province with approximately 12.9 million residents representing approximately 39 per cent of Canada s total population. Ontario consumed approximately 148,700 GWh of electricity in 2008. Ontario Power Generation Inc., the successor to the generation business of Ontario s former integrated electric utility, controls two thirds of Ontario s approximately 32,000 MW of installed capacity, the balance of which is owned by municipal electric utilities and private independent power producers or industrial consumers.

In October 2004, the provincial government of New Brunswick officially opened the electricity market to partial competition and corporate reorganization. *The Electricity Act (2004)* allows wholesale and industrial consumers to purchase power from either New Brunswick Power or a competing supplier. The new competitive market does not extend to retail customers, businesses or small industries. In 2007, New Brunswick announced the Charter for Change requiring ten per cent of electricity purchases to be from renewable sources commencing in 2016.

The Corporation expects that the demand for electricity will continue to grow in its target markets over the long-term. In addition to increased demand, the market for electricity in some of these regions has undergone deregulation. Legislation in Alberta and Ontario and many states in the United States have mandated the unbundling of generation, transmission and distribution services which were traditionally provided by vertically integrated utilities to promote competition in the market for generation, which caused some integrated utilities to sell all or parts of their generation assets. While the pace of this process has changed, the Corporation believes that the combination of increased demand for electricity, deregulation and the increased availability of generation assets may provide an opportunity to increase its generation capacity and leverage its Commercial Operations Development capabilities, provided that in doing so, the financial position of the Corporation is not compromised.

Australia is heavily dependent on coal for electricity, more so than any other developed country except Denmark and Greece. About 80 per cent of power produced is derived from coal. Natural gas is increasingly used for electricity, especially in South Australia and Western Australia. The Australian Bureau of Agriculture and Resource Economics (ABARE) estimated total production of 272,000 GWh for 2008 with a growth rate of approximately 2.4 per cent per annum from 2009 to 2012. The major reform in the Australian electricity industry involved the establishment in southern and eastern Australia of the National Electricity Market (NEM). In Western Australia, where TransAlta s power assets are located, a new Wholesale Electricity Market (WEM) was introduced in late 2006. Total installed capacity in the WEM is about 4,500 MW, while TransAlta s capacity in the region is approximately 345 MW. TransAlta enjoys a solid competitive advantage in power supply to mining operations, especially remote mining operations, and has built up significant knowledge and expertise in this field.

Competitive Strengths

The Corporation believes it is well positioned to achieve its business strategy due to its competitive strengths, which include the following:

Financial strength - The Corporation has investment grade ratings from Moody s Investor Services, Inc. (**Moody s**), Standard & Poor s, a division of the McGraw Hill Companies, Inc. (**S&P**) and Dominion Bond Rating Service Limited (**DBRS**).

Stable cash flow base Approximately 70 per cent of the Corporation s generating capacity is contracted through PPAs or LTC s for the next five years. Revenues received under contractual arrangements are not subject to short-term fluctuations in the spot price for electricity.

Fuel diversity - The Corporation has a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, geothermal and wind. The Corporation believes that this mix reduces the impact on corporate performance in the event of external events affecting one fuel source.

Management team - The Corporation s management team has substantial industry, international and local market experience.

Commercial Operations Development expertise - The Corporation believes that its Commercial Operations Development group has enhanced returns from the Corporation s existing generation base and has allowed the Corporation to obtain more favourable pricing for uncommitted electricity, secure fuel supply on a cost-effective basis and fulfill electricity delivery obligations in the event of an outage.

Ownership or control of coal supply - The Corporation owns, controls or leases extensive coal reserves in Alberta that provide a long-term and stable source of fuel for all of its thermal generation capacity in Alberta. The Corporation s mines in Alberta contain some of the lowest sulphur coal in North America, averaging 0.25 per cent sulphur at the Whitewood mine and 0.25 per cent at the Highvale mine. Coal with lower sulphur content emits less sulphur dioxide when it is burned.

Wind Generation - The Corporation is one of the largest owners and operators of wind generation in Canada. The Wind management team has developed key relationships with customers, suppliers and policy makers that provide a competitive advantage in the development, operations and marketing of wind generation.

Environment The Corporation is a recognized leader in Sustainable Development and has taken early preventative action on a number of environmental fronts in advance of regulation.

Capital Expenditures

Capital expenditures for property and investments (including acquisitions) by TransAlta for the past five years were:

2008	$1,006.4 million	2005	$325.5 million
2007	$599.7 million	2004	$345.7 million
2006	$224.9 million		

ENVIRONMENTAL RISK MANAGEMENT

TransAlta is subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of electrical and thermal energy and surface mining. TransAlta is committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of its operations. TransAlta works with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

TransAlta s approach to managing its environmental, health and safety (**EHS**) risks has three elements:

- Compliance based activities, such as permitting and reporting;
- ISO based EHS Management systems and programs, such as safety programs and auditing; and
- Longer term strategic initiatives, including climate change and government policy development.

These elements are integrated into TransAlta s corporate wide operations and management systems. They are designed to mitigate risks of TransAlta s activities to employees, the public and the environment, and to address potential competitive risks from future changes in environmental policy. They are also supportive of TransAlta s corporate commitment to sustainability.

To meet regulatory requirements and improve environmental performance, TransAlta made environmental operating and capital expenditures in fiscal year 2008 of approximately $47 million. Environmental expenditures are generally defined as expenditures incurred to comply with Canadian or international environmental regulations, conventions or voluntary agreements.

All TransAlta s facilities are in material compliance with existing regulatory requirements. Environmental risk at the plants operated by TransAlta has been reduced by actions in several areas:

- Continued investment in mercury control technology evaluation leading to expected installation of mercury capture equipment at our Alberta coal plants in 2010, and at our Centralia, Washington coal plant by 2012;
- Uprate improvements delivering higher efficiency generation at the Sundance plant;
- Continued program of compliance and management system audits at all facilities;
- The planned decommissioning of the older Wabamun thermal plant in 2010;
- Acquisition of carbon offsets;
- Continued expansion of the wind energy business, with minimal emissions footprint; and
- Development of a carbon capture and storage demonstration project in Alberta.

On a longer time horizon, TransAlta anticipates future environmental regulatory developments in areas such as climate change, air quality and water. Regulatory changes and policy developments are tracked in all relevant jurisdictions. Relevant regulatory developments are discussed below.

Canada

On January 24, 2008, the Government of Alberta announced its long-term intention to cut greenhouse gas emissions to 14 per cent below 2005 levels by 2050 through developing and implementing carbon capture and storage technologies, developing conservation and energy efficiency programs, and through increased investment in clean energy technologies. We are assessing the impact of this proposal upon our operations and our own investment in environmental technologies and programs.

Alberta continues to maintain its greenhouse gas (**GHG**) regulatory regime which was implemented in July 1, 2007, under the *Climate Change and Emissions Management Amendment Act*. Under the legislation, baselines and targets for GHG intensity are set on a facility-by-facility basis. The legislation and subsequent regulations require a 12 per cent reduction in GHG emission intensity from a baseline of the average of 2003 to 2005 emission levels. New facilities or those in operation for less than three years are exempt; however, upon the fourth year of operations, the facility baseline is established and reduction requirements gradually increase until the eighth year by which time emissions must be 12 per cent below the established baseline. Emissions over the baseline must be mitigated either through contributions to an Alberta Technology Fund at $15 per tonne, or through the purchase and retirement of Alberta-based offsets from non-regulated sectors. The PPAs for our Alberta-based coal facilities contain change-in-law provisions that allow us to recover compliance costs from the PPA customers. After flow-through, the annual net compliance costs for 2008 are estimated to be $1.2 million.

Mercury reduction requirements in Alberta are established at a 70 per cent reduction by 2010. We submitted our mercury control plan in March 2007. Detailed mercury technology testing was conducted in 2008 and further is expected in 2009. Engineering work is underway to have mercury controls fully implemented in 2010.

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

The Canadian government indicated in January 2009 that it intends to develop an integrated cap and trade program for greenhouse gas emissions, in cooperation with its North American trading partners. There are few details of this new approach and it is therefore not possible to determine what compliance costs would be or how it might affect the previous approach.

In August 2007, the Government of Ontario announced its climate change action plan which included a target to reduce GHG emissions by 6 per cent below 1990 level by 2014. Subsequently the government has indicated its intention to implement a cap and trade system for greenhouse gases by 2010, although no additional legislation or details have been developed.

United States

In the United States, the Washington State Climate Bill 6001 was enacted and came into effect on July 22, 2007. Our operations will not be impacted by the bill s performance standards at the current time, provided the facilities do not change ownership or enter into power sales contracts longer than five years.

On December 12, 2008, Washington State introduced draft legislation to enable a cap and trade system to be implemented by 2012. Specific details of caps and allocations will be developed in 2009. In parallel, Washington State is engaged with other western states in the Western Climate Initiative (**WCI**) to examine a regional cap and trade system for carbon. On September 23, 2008, the WCI released its design for a regional greenhouse gas cap and trade system, which will be influential in individual state regulation development. At this point, there are no indications as to how these initiatives will impact our fossil-fired assets in Washington.

The United States Federal Government continues to contemplate a number of proposed GHG related bills, but to date no clear outcome or schedule is evident. In February 2009, the Administration provided a budget plan for implementing an economy-wide federal cap & trade system to reduce greenhouse gases to 14 per cent below 2005 levels by 2020. The budget includes a plan to auction 100 per cent of the required allowances, with approximately $150B of the revenue raised from auctioning to be allocated to clean energy investments over 10 years.

TransAlta is an active participant in the Canadian Clean Power Coalition, which is committed to developing clean coal technology in Canada. The coalition has several engineering initiatives underway which will provide important guidance on ultimate clean coal solutions for TransAlta s facilities. The Corporation is also exploring the possibilities for a CO2 network pipeline through the ICON industry consortium.

In April 2008, TransAlta announced a partnership with Alstom LLC to develop a one million tonne/year carbon capture and storage project at one of TransAlta s coal-fired power stations in Alberta. This project has been shortlisted by the Alberta Government for contributory funding as part of the province s $2 billion CCS program, with a decision expected by June 30, 2009.

Environmental issues concerning water use are managed within the ISO 14001 framework. TransAlta continues to work with regulators in each jurisdiction in which it operates, to ensure water is used wisely on site and that all regulations pertaining to water and wetlands management, both on and off site, are met at all times.

TransAlta s environmental efforts have been recognized by the Dow Jones North American Sustainability Index for four years in a row. The Index represents the best environmental performance leaders in North America. In 2008, TransAlta also participated in the global Carbon Disclosure Project which requires detailed assessments of corporate climate change plans and actions.

To date, TransAlta does not believe that its competitive position in the wholesale generation business has been adversely affected by environmental concerns. TransAlta continues to make operational improvements and investments to its existing generating facilities to reduce the environmental impact of generating electricity.

RISK FACTORS

Readers should consider carefully the risk factors set forth below as well as the other information contained and incorporated by reference in this Annual Information Form. For a further discussion of risk factors affecting TransAlta, please refer to Risk Factors in the Annual MD&A, which is incorporated by reference herein.

A reference herein to a material adverse effect on the Corporation means such an effect on the Corporation on its business, financial condition, results of operations, or its cash flows, as the context requires.

Changes in the prices and availability of fuel supplies required to generate electricity, and in the price of electricity, may materially adversely affect the Corporation.

A significant portion of the Corporation s revenues are tied, either directly or indirectly, to the market price for electricity in the markets in which the Corporation operates. Market electricity prices are impacted by a number of factors, including: the price of fuel that is used to generate other sources of electricity (and, accordingly, certain of the factors that affect the price of fuel described below); the management of generation and the amount of excess generating capacity relative to load in a particular market; the cost of controlling emissions of pollution, including potentially the cost of carbon; the structure of the particular market; and weather conditions that impact electrical load. As a result, the Corporation cannot accurately predict future electricity prices and electricity price volatility could have a material adverse effect on the Corporation.

The Corporation buys natural gas and some of its coal to supply the fuel needed to generate electricity. The Corporation could be materially adversely affected if the cost of fuel that it must buy to generate electricity increases to a greater degree than the price that it can obtain for the electricity that it sells. Several factors affect the price of fuel, many of which are beyond the Corporation s control, including:

- prevailing market prices for fuel, including any associated transportation costs;
- demand for energy products;
- increases in the supply of energy products in the wholesale power markets; and
- the extent of fuel transportation capacity or cost of fuel transportation service into the Corporation s markets.

Changes in any of these factors may increase the Corporation s cost of producing power or decrease the amount of revenue it receives from the sale of power, which could materially adversely affect the Corporation.

The rules and regulations in the various markets in which the Corporation operates are subject to change, which may materially adversely affect the Corporation.

Certain of the markets in which the Corporation operates and intends to operate are subject to significant regulatory oversight and control. The Corporation is not able to predict whether there will be any further changes in the regulatory environment, including potential regulation of the rates allowed to be charged and the capital structure of wholesale generating companies such as the Corporation, or what the ultimate effect of a changing regulatory environment will have on its business. Existing market rules and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Corporation or its facilities which could have a material adverse effect on the Corporation. The Corporation cannot guarantee that it will be able to adapt its business in a timely manner in response to any changes in the regulatory regimes in which it operates, and such failure to adapt could have a material adverse effect on the Corporation.

Regulatory authorities may also from time to time investigate the Corporation s activities in the markets in which it operates or pursues trading. Such investigations may result in sanctions or penalties which may materially affect the Corporation s future activities or financial status.

The Corporation s facilities are also subject to various licensing and permitting requirements in the jurisdictions in which they operate, many of which licenses and permits need to be renewed from time to time. If the Corporation is unsuccessful in renewing such licenses or permits, or the terms of such licenses or permits are changed in a manner that is adverse to the Corporation, the Corporation could be materially adversely affected.

Any changes in the rules and regulations of provincial or state public utility commissions or other regulatory bodies in the other markets in which the Corporation competes or may compete in the future may materially adversely affect the Corporation.

Many of the Corporation s activities and properties are subject to environmental requirements and changes in, or liabilities under, these requirements may materially adversely affect the Corporation.

The Corporation s operations are subject to extensive Canadian, United States and other federal, provincial, state and local environmental laws, regulations and guidelines, relating to the generation and transmission of electrical and thermal energy and surface mining, pertaining to pollution and protection of the environment, health and safety and governing among other things, air emissions, water usage and discharges, storage, treatment and disposal of waste and other materials and remediation of sites and land use responsibility (collectively, environmental regulation). These laws can impose liability for costs to investigate and remediate contamination without regard to fault and under certain circumstances liability may be joint and several resulting in one responsible party being held responsible for the entire obligation. Environmental regulation can also impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transport, treatment and disposal of hazardous substances and waste and can impose clean-up, disclosure or other responsibilities with respect to spills, releases and emissions of various substances to the environment. Environmental regulation can also require that facilities and other properties associated with the Corporation s operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, there is an increasing level of environmental regulation regarding the use, treatment and discharge of water and increasing anticipation of new or additional emission regulations at a national level in Canada and the United States which may impose different compliance requirements standards on the Corporation. These various compliance standards may result in duplicate compliance and costs requirements for the Corporation or may impact our ability to operate our facilities.

To comply with environmental regulation, the Corporation must incur material capital and operating expenditures relating to environmental monitoring, emissions and effluent control equipment and processes, emissions measurement, verification and reporting, emissions fees and other compliance activities or obligations. The Corporation expects to continue to have environmental expenditures in the future. Stricter standards, new or greater regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Corporation subject to environmental regulation and the implementation of provincial, state and national GHG emissions, mercury emissions or other air emissions regulation in a jurisdiction in which we operate could increase the amount of these expenditures. To the extent these expenditures cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs (as defined herein) or otherwise, the costs to the Corporation could be material. In addition, compliance with environmental regulation might result in restrictions on some of the Corporation s operations. If the Corporation does not comply with environmental regulation, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on the Corporation or to curtail its operations and significant expenditures on compliance, new equipment or technology, reporting obligations and research and development. In addition to environmental regulation, the Corporation could also face civil liability in the event that private parties seek to impose liability on the Corporation for property damage, personal injury or other costs and losses. The Corporation cannot guarantee that lawsuits or administrative or investigative actions will not be commenced against it otherwise affect its operations and assets. If an action is filed against the Corporation or which may otherwise affect its operations and assets, the Corporation could be required to make substantial expenditures to defend or evidence its activities or to bring the Corporation, its operations and assets into compliance, which could have a material adverse effect on the Corporation.

A number of recent federal, provincial, state and local regulatory efforts continue to focus on potential climate change or GHG emissions regulation. GHG legislation is in early stages of evolution in Canada and the United States, and it is relatively early to determine the impact of potential GHG reduction requirements. For example, the issues of jurisdiction to regulate GHG emissions, as between the federal and provincial governments, and whether both levels of government will be able to agree on harmonization of desired GHG emissions reduction requirements, also remains outstanding in Canada. In addition, Washington is part of a group of states in the Western Climate Initiative, which have announced the intention to implement a cap and trade program for GHGs by 2012. Mandatory GHG emissions reductions requirements are expected to impose increased costs on the Corporation, as is expected to be the case generally for thermal power producers in North America. The Corporation is subject to other air quality regulation including mercury regulation. At this time, the Corporation cannot assess the potential impact of future mercury regulation at its United States facilities. To the extent new or additional GHG, mercury or other air emission regulations may require the Corporation to incur costs that cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs or otherwise, the costs could be material and have a material adverse effect on the Corporation.

The Corporation s surface mining operations are subject to laws and regulations establishing mining, environmental protection and reclamation standards for all aspect of surface mining. As a mine owner or operator the Corporation must obtain permits from the applicable regulatory body providing for the authorization of certain mining operations that result in a disturbance of the surface. These requirements seek to limit the adverse impacts of coal mining and more restrictive requirements may be adopted from time to time. TransAlta as a mine owner or operator may also be required to submit a bond or otherwise secure payment of certain long-term obligations including mine closure or reclamations costs. Surety bond costs have increased in recent years while the market terms of such bonds have generally become more unfavourable. In addition, the number of companies willing to issue surety bonds has decreased. TransAlta could be required to self fund these obligations should it be unable to renew or secure the required surety bonds for its mining operations.

Changes in general economic conditions may have a material adverse effect on the Corporation.

Adverse changes in general economic and market conditions could negatively impact product demand, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, credit risk, and counterparty risk, which could have a material adverse effect on the Corporation. Changes in interest rates can impact the Corporation s borrowing costs and the capacity revenues the Corporation receives pursuant to the Alberta government mandated power purchase arrangements (the **Alberta PPAs**).

Under the government mandated power purchase arrangements pursuant to which the Corporation operates most of its facilities in Alberta, the Corporation is subject to certain risks, including the possibilities of penalties for unplanned outages and the burden of increased costs required to maintain and operate its generation facilities.

The majority of the Corporation s Alberta coal fired and hydroelectric generating plants operate under the Alberta PPAs which established committed capacity and electrical energy generation requirements and availability targets to be achieved by each coal fired plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which power will be supplied. Under the Alberta PPAs applicable to coal fired plants, in the event of an unplanned outage, other than an outage determined to be caused by force majeure, the Corporation must pay a penalty for the lost production based upon a price equal to the 30 day trailing average of Alberta market electricity prices. Consequently, an unplanned outage could have a material adverse effect on the Corporation.

The Corporation bears some of the impact of increases in its operating costs (other than increases arising as a result of a change of law as such term is defined in the Alberta PPAs) because the price at which the Corporation is able to sell its generation under the Alberta PPAs is based on a schedule of forecast fixed costs. Many of the forecast costs will be determined by indices, formulae or other means for the entire term of the Alberta PPA. The Corporation s actual results will vary and depend on performance compared to the forecasts on which the Alberta PPAs are based. Operating costs could increase as a result of a number of factors which are beyond the Corporation s control. A significant increase in the Corporation s operating costs could have a material adverse effect on the Corporation.

From time to time during the term of the Alberta PPAs, issues may arise regarding the intended operation of the Alberta PPAs which may require certain provisions of the Alberta PPAs to be interpreted, and the interpretations given may not be favourable to the Corporation. In such circumstances, the Corporation could be materially adversely affected.

The operation and maintenance of the Corporation s facilities involves risks that may materially adversely affect the Corporation.

The operation, maintenance, refurbishment, construction and expansion of power generation facilities involve risks, including breakdown or failure of equipment or processes, fuel interruption and performance below expected levels of output or efficiency. Certain of the Corporation s generation facilities, particularly in Alberta, were constructed many years ago and may require significant capital expenditures to maintain peak efficiency or to maintain operations at all. In addition, weather related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of the Corporation s facilities and may materially adversely affect the Corporation.

The Corporation has entered into on going maintenance and service agreements with the manufacturers of certain critical equipment. If a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support, the Corporation may have to enter into alternative arrangements with other providers if it cannot perform the maintenance itself. These arrangements could be more expensive to the Corporation than its current arrangements and this increased expense could have a material adverse effect on the Corporation. If the Corporation is unable to enter into satisfactory alternative arrangements, the inability of the Corporation to access technical expertise or parts could have a material adverse effect on the Corporation.

While the Corporation maintains an inventory, or otherwise makes arrangements to obtain, spare parts to replace critical equipment and maintains insurance for property damage to protect against operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties which could result if the Corporation is unable to operate its generation facilities at a level necessary to comply with sales contracts (including Alberta PPAs).

The Corporation may be subject to the risk that it is necessary to operate a plant at a capacity level beyond that which the Corporation has contracted to provide steam in order to fulfill a contract. In such circumstances the costs to produce the steam being sold may exceed the revenues derived therefrom.

The Corporation relies on transmission lines that it does not own or control, which may hinder its ability to deliver electricity.

The Corporation depends on transmission and distribution facilities that are owned and operated by utilities and other power companies to deliver the electricity the Corporation generates. An extended disruption in transmission would impact the Corporation s ability to sell and deliver electricity, which could have a material adverse effect on the Corporation.

The Corporation may be adversely affected if its supply of water is materially reduced.

Hydroelectric, natural gas, and coal-fired plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to the Corporation s facilities. Any material reduction in the water flow to the Corporation s facilities would limit the Corporation s ability to produce and market electricity from these facilities and could have a material adverse effect on the Corporation. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in Alberta. Any such change in regulations could have a material adverse effect on the Corporation.

Trading risks may have a material adverse affect on the Corporation.

The Corporation s trading and marketing business frequently involves the establishment of trading positions in the wholesale energy markets on both a long term and short term basis. To the extent that the Corporation has long positions in the energy markets, a downturn in the markets is likely to result in losses from a decline in the value of such long positions. Conversely, to the extent that the Corporation enters into forward sales contracts to deliver energy the Corporation does not own, or take short positions in the energy markets, an upturn in the energy markets is likely to expose the Corporation to losses as it attempts to cover any short positions by acquiring energy in a rising market.

In addition, from time to time the Corporation may have a trading strategy consisting of simultaneously holding a long position and a short position, from which the Corporation expects to earn a profit based on changes in the relative value of the two positions. If, however, the relative value of the two positions changes in a direction or manner the Corporation did not anticipate, it could realize losses from such a paired position.

If the strategy the Corporation uses to hedge its exposures to these various risks is not effective, it could incur significant losses. The Corporation s trading positions are subject to the level of volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect the Corporation s positions which could also have a material adverse effect on the Corporation.

While the Corporation uses a number of risk management controls to limit its exposure to risks arising from its trading activities, including value-at-risk, volumetric and term limits and restrictions on authorized instruments, the Corporation cannot guarantee that losses will not occur and such losses, if material, could have a material adverse effect on the Corporation.

Because of the Corporation s multinational operations, the Corporation is subject to currency rate risk and regulatory and political risk.

A significant part of the Corporation s revenues and expenditures are in U.S. and other currencies. Fluctuations in the exchange rate between these currencies and the Canadian dollar could have a negative effect on the Corporation. While the Corporation attempts to manage this risk through its use of hedging instruments, including cross currency swaps, forward exchange contracts and by matching revenues and expenses by currency at the Corporate level, fluctuations in these exchange rates may have a material adverse effect on the Corporation.

In addition to currency rate risk, the Corporation s foreign operations may be subject to regulatory and political risk. Any change to the regulations governing power generation or the political climate in countries where the Corporation has operations could impose additional costs and have a material adverse effect on the Corporation.

The Corporation may have difficulty raising needed capital in the future, which could significantly harm its business.

To the extent that the Corporation s sources of cash and cash flow from operations are insufficient to fund the Corporation s activities, it may need to raise additional funds. Additional financing may not be available when needed and, if such financing is available, it may not be available on terms favourable to the Corporation.

The Corporation s debt securities will be structurally subordinated to any debt of its subsidiaries that is currently outstanding or may be incurred in the future.

The Corporation operates its business through, and a majority of its assets are held by, its subsidiaries, including partnerships. The Corporation s results of operations and ability to service indebtedness are dependent upon the results of operations of its subsidiaries and the payment of funds by these subsidiaries to it in the form of loans, dividends or otherwise. The Corporation s subsidiaries will not have an obligation to pay amounts due pursuant to any debt securities issued by the Corporation or make any funds available for payment of debt securities issued by the Corporation, whether by dividends, interests, loans, advances or other payments. In addition, the payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions.

In the event of the liquidation of any subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used to pay the Corporation s indebtedness, including any debt securities issued by the Corporation. Such indebtedness and any other future indebtedness of such subsidiaries would be structurally senior to any debt securities issued by the Corporation.

The Corporation s subsidiaries have financed some investments using non recourse project financing. Each non recourse project loan is structured to be repaid out of cash flow provided by the investment. In the event of a default under a financing agreement which is not cured, the lenders would generally have rights to the related assets. In the event of foreclosure after a default, the Corporation s subsidiary may lose its equity in the asset or may not be entitled to any cash that the asset may generate. Although a default under a project loan will not cause a default with respect to any debt securities issued by the Corporation, it may materially affect the Corporation s ability to service its outstanding indebtedness.

Certain of the contracts to which the Corporation is a party require the Corporation to provide collateral against its obligations.

The Corporation is exposed to risk under certain electricity and natural gas purchase and sale contracts entered into for the purposes of hedges and proprietary trading. The terms and conditions of these contracts require the Corporation to provide collateral when the fair value of these contracts is in excess of any credit limits granted by the Corporation s counterparties and the contract obliges the Corporation to provide the collateral. The change in fair value of these contracts occurs due to changes in commodity prices. These contracts include: (i) purchase agreements, when forward commodity prices are less than contracted prices; and (ii) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in the Corporation s creditworthiness by certain credit rating agencies may decrease the credit limits granted by the Corporation s counterparties and accordingly increase the amount of collateral the Corporation may have to provide.

If counterparties to the Corporation s contracts are unable to meet their obligations, the Corporation may be materially adversely affected.

If purchasers of the Corporation s electricity, steam or other contractual counterparties of the Corporation default on their obligations, the Corporation may be materially adversely affected. While the Corporation seeks to control its exposure to credit risk by considering the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, the Corporation cannot guarantee that it will be successful in identifying credit worthy customers. Moreover, while the Corporation seeks to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, it cannot guarantee that it will be successful in doing so. If counterparties to the Corporation s contracts are unable to meet their obligations, the Corporation could suffer a reduction in revenue which could have a material adverse effect on the Corporation.

Insurance coverage may not be sufficient.

The Corporation has insurance for its facilities, including all risk property insurance, commercial general public liability insurance, boiler and machinery coverage, replacement power and business interruption insurance, in amounts and with deductibles that the Corporation considers appropriate. The Corporation s insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for any loss of or any damage to any of its generation facilities may not be sufficient to permit it to continue to make payments on its debt.

Provision for income taxes may not be sufficient.

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. In addition, the Corporation s tax filings are subject to audit by taxation authorities. While the Corporation believes that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, the Corporation cannot guarantee that it will not have disagreements with the Canada Revenue Agency or other taxation authorities with respect to the Corporation s tax filings.

The Corporation may be unsuccessful in the defence of legal actions.

The Corporation is occasionally named as a defendant in various claims and legal actions. There can be no assurance that the Corporation will be successful in the defence of each of these claims and legal actions or that any claim or legal action that is decided adverse to the Corporation will not materially adversely affect the Corporation.

If the Corporation fails to attract and retain key personnel, it could be materially adversely affected.

The loss of any of the Corporation s key personnel or its inability to attract, train, retain and motivate additional qualified management and other personnel could have a material adverse effect on the Corporation. Competition for these personnel is intense and there can be no assurance that the Corporation will be successful in this regard.

If the Corporation is unable to successfully negotiate new collective bargaining agreements with its unionized workforce, as required from time to time, it will be adversely affected.

While the Corporation believes it has a good relationship with its unionized employees, the Corporation cannot guarantee that it will be able to successfully negotiate or renegotiate its collective bargaining agreements on terms agreeable to the Corporation. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on the Corporation.

EMPLOYEES

As of December 31, 2008, the Corporation had 2,110 full and part-time employees, of which 1,529 were employed in TransAlta s generation business and 147 were employed in TransAlta s energy marketing business. Approximately 46 per cent of the Corporation s employees are represented by labour unions. The Corporation is currently a party to 11 different collective bargaining agreements. Overall in 2008, the Corporation renewed three of the agreements, an additional five agreements are expected to be re-negotiated in 2009, and the remaining three agreements are expected to be re-negotiated in 2010.

CAPITAL STRUCTURE

General

The Corporation s authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. As at March 12, 2009, there were 197,849,306 common shares outstanding and no first preferred shares were outstanding.

Common Shares

Each common share of the Corporation entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Corporation, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board of Directors, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of the assets of the Corporation upon a liquidation, dissolution or winding up and subject to prior rights and privileges attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

First Preferred Shares

The Corporation is authorized to issue an unlimited number of first preferred shares, issuable in series and, with respect to each series, the Board of Directors is authorized to fix the number of shares comprising the series and determine the designation, rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

The first preferred shares of all series rank senior to all other shares of the Corporation with respect to priority in payment of dividends and with respect to distribution of assets in the event of liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital. Holders of first preferred shares are entitled to receive cumulative quarterly dividends on the subscription price thereof as and when declared by the Board of Directors at the rate established by the Board of Directors at the time of issue of shares of a series. No dividends may be declared or paid on any other shares of the Corporation unless all cumulative dividends accrued upon all outstanding first preferred shares have been paid or declared and set apart. In the event of the liquidation, dissolution or winding up of the Corporation, or a reduction of stated capital, no sum shall be paid or assets distributed to holders of other shares of the Corporation until the holders of first preferred shares shall have been paid the subscription price of the shares, plus a sum equal to the premium payable on a redemption, plus a sum equal to the arrears of dividends accumulated on the first preferred shares to the date of such liquidation, dissolution, winding up, or reduction of stated capital, as applicable. After payment of such amount, the holders of first preferred shares shall not be entitled to share further in the distribution of the assets of the Corporation.

The Corporation s Board of Directors may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon the Corporation failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board of Directors then consists of less than 16 directors, or three directors if the Board of Directors consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Subject to the share conditions attaching to any particular series providing to the contrary, the Corporation may redeem first preferred shares of a series, in whole or from time to time in part, at the redemption price applicable to each series and the Corporation has the right to acquire any of the first preferred shares of one or more series by purchase for cancellation in the open market or by invitation for tenders at a price not to exceed the redemption price applicable to the series.

CREDIT RATINGS

Issuer Rating

As of December 31, 2008, the Corporation s issuer rating from S&P was BBB (stable), from Moody s was Baa2 (stable), and from DBRS was BBB (stable).

Senior Unsecured Long Term Debt

As of December 31, 2008, the Corporation s senior unsecured long-term debt is rated BBB (stable) by DBRS, BBB (stable) by S&P and Baa2 (stable) by Moody s. The ratings for debt instruments range from a high of AAA to a low of D in the case of both DBRS and S&P and from a high of Aaa to a low of C in the case of Moody s.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is more susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. High or Low grades indicate the relative standing within a rating category. DBRS also assigns rating trends to each of its ratings to give investors an understanding of DBRS opinion regarding the outlook for the rating in question.

According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on such obligations than on obligations in the higher rating categories. The ratings from AA to B may be modified by the addition of a plus (+) or minus ( ) sign to show relative standing within the major rating categories.

According to the Moody s rating system, debt securities rated Baa are subject to moderate credit risk. They are considered medium grade and as such may possess certain speculative characteristics. Numerical modifiers 1, 2 and 3 are applied to each rating category, with 1 indicating that the obligation ranks in the higher end of the category, 2 indicating a mid range ranking and 3 indicating a ranking in the lower end of the category.

Note Regarding Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to the Corporation s outstanding securities by S&P, Moody s and DBRS, as applicable, are not recommendations to purchase, hold or sell such securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by S&P, Moody s or DBRS in the future if, in its judgement, circumstances so warrant.

DIVIDENDS

In setting its dividend, TransAlta s Board of Directors considers the Corporation s financial performance and balances liquidity requirements, capital reinvestment and returning capital to shareholders, with a policy of paying annual dividends to its shareholders in the range of 60 to 70 per cent of comparable earnings. The payment and level of future dividends on the common shares are determined by the Board of Directors of TransAlta upon consideration of such factors. TransAlta has declared and paid the following dividends per share on its outstanding common shares for the past three years:

Period		Dividend per Common Share
2006	First Quarter	$0.25
	Second Quarter	$0.25
	Third Quarter	$0.25
	Fourth Quarter	$0.25
2007	First Quarter	$0.25
	Second Quarter	$0.25
	Third Quarter	$0.25
	Fourth Quarter	$0.25
2008	First Quarter	$0.27
	Second Quarter	$0.27
	Third Quarter	$0.27
	Fourth Quarter	$0.27

On January 29, 2009, the Corporation s Board of Directors declared a cash dividend of $0.29 per common share, payable on April 1, 2009 to shareholders of record on March 1, 2009.

MARKET FOR SECURITIES

TransAlta s common shares are listed on the TSX under the symbol TA and the New York Stock Exchange under the symbol TAC . The following table sets forth the reported high and low trading prices and trading volumes of the Corporation s common shares as reported by the TSX for the periods indicated:

	Price ($)		
Month	**High**	**Low**	**Volume**
2008			
January	34.00	29.85	15,201,560
February	35.80	32.01	27,280,079
March	35.73	30.03	31,739,588
April	34.27	30.83	16,237,231
May	36.16	33.24	16,671,590
June	37.30	34.65	17,308,802
July	38.10	30.71	42,637,530
August	37.73	34.59	20,057,372
September	36.88	26.53	28,180,867
October	29.85	20.00	24,458,282
November	24.59	21.00	14,517,240
December	24.45	20.77	11,835,571
2009			
January	26.60	21.13	10,881,392
February	22.96	18.50	16,191,905
March 1 to 12	21.05	17.96	5,609,514

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of the directors and officers of TransAlta as at March 12, 2009, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve to the Board is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
William D. Anderson Ontario, Canada	2003	*Corporate Director*. Mr. Anderson was President of BCE Ventures (a subsidiary of BCE Inc.) from 2001 to 2005 (telecommunications) and prior to that Chief Financial Officer (CFO) of BCE Inc., Bell Canada Inc. and Bell Cablemedia plc (telecommunications). As President of BCE Ventures, he was responsible for a number of significant operating companies as well as being Chief Executive Officer (CEO) of Bell Canada International Inc. In his CFO roles, Mr. Anderson was responsible for all financial operations of the respective companies and executed numerous debt and equity financings, corporate acquisition and disposition transactions as well as corporate and operational restructurings. Mr. Anderson is a director of Gildan Activewear Inc. and of MDS Inc. He is a past director at BCE Emergis Inc., Bell Cablemedia plc, Bell Canada International Inc., CGI Group Inc., Four Seasons Hotels Inc., Sears Canada Inc., and Videotron Holdings plc. At TransAlta, Mr. Anderson is Chair of the Audit and Risk Committee of the Board. Mr. Anderson holds a bachelor degree in business administration from the University of Western Ontario (London, ON) and is a Chartered Accountant.
Stephen L. Baum New Hampshire, U.S.A.	2008	*Corporate Director*. Mr. Baum was Chairman and CEO of Sempra Energy from December 1996 to February 2006, a San Diego-based Fortune 500 energy services holding company formerly known as Enova Corporation. Previous to that, Mr. Baum was President, CEO and Vice-Chairman of Sempra Energy. Prior to that he was Chairman, CEO and a member of the board of directors of Enova Corporation, the parent company of San Diego Gas & Electric (SDG&E) where he served in various officer positions including General Counsel. Before joining SDG&E, he was Senior Vice President and General Counsel of the New York Power Authority. He has also held various legal positions, including General Attorney at Orange & Rockland Utilities, and as an associate with the law firm of Curtis, Mallet-Prevost, Colt & Mosle in New York City. ***Mr. Baum is a member of the board of directors of Computer Science Corporation and is Chair of its Audit Committee. He is also a Senior Advisor to SkyFuel Inc., a solar company.*** ***At TransAlta, Mr. Baum is a member of the Audit and Risk Committee and the Human Resources Committee of the Board.*** ***Mr. Baum is a graduate of Harvard University and the University of Virginia Law School. He has also served as a Captain in the U.S. Marine Corps.***
Stanley J. Bright (1)	1999	

Maryland, U.S.A.

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

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

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

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Timothy W. Faithfull England, U.K.	2003	***Corporate Director***. Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc (energy), where he filled diverse international roles principally in oil products and LNG project development. As President and CEO of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line, the first fully integrated oil sands venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operations of Shell International Trading and Shipping Company from 1993 to 1996. He was Chairman and CEO of Shell Eastern Petroleum in Singapore from 1996 to 1999, including Shell s main refinery and oil products trading for Asia Pacific. During his time in Singapore he was a director of DBS Bank, and the Port of Singapore Authority. He was a trustee of the main Singapore Arts/Theatre complex. In Calgary, he served on the board of the Calgary Health Trust and the Epcor Arts Centre. Mr. Faithfull is a director of Canadian Pacific Railway Limited, Shell Pension Trust Limited, AMEC plc and Enerflex Systems Income Fund. At TransAlta, Mr. Faithfull is a member of the Audit and Risk Committee and the Human Resources Committee of the Board. Mr. Faithfull holds a master of arts degree in philosophy, politics and economics from the University of Oxford, U.K.
Ambassador Gordon D. Giffin Georgia, U.S.A	2002	***Lawyer and Senior Partner, McKenna, Long & Aldridge LLP*** *(attorneys)*. From 1997 to 2001, Mr. Giffin served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy. Prior to this appointment, he practised law for 18 years as a senior partner in Atlanta, Georgia and Washington, D.C. His practice focused on energy regulatory work at the state and federal levels. Prior to that, he served as Chief Counsel and Legislative Director to United States Senator Sam Nunn, with responsibility for the legal and legislative operations of the office. In 2001, Mr. Giffin returned to private practice where he specialized in state and federal regulatory matters, including those related to trade, energy and trans-border commerce. Mr. Giffin is a director of Canadian Imperial Bank of Commerce, Canadian National Railway Company, Canadian Natural Resources Limited, and Ontario Energy Savings Ltd. At TransAlta, Mr. Giffin is Chair of the Governance and Environment Committee of the Board. Mr. Giffin holds a bachelor of arts from Duke University (Durham, NC) and a juris doctorate from Emory University School of Law (Atlanta, GA).

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
C. Kent Jespersen Alberta, Canada	2004	***Corporate Director***. Mr. Jespersen has been Chair and CEO of La Jolla Resources International Ltd. since 1998 (advisory and investments). He has also held senior executive positions with NOVA Corporation of Alberta, Foothills Pipe Lines Ltd., and Husky Oil Limited before assuming the presidency of Foothills Pipe Lines Ltd. and later, NOVA Gas International Ltd. (NOVA). At NOVA, he led the non-regulated energy services business (including energy trading and marketing) and all international activities. Mr. Jespersen is Chairman and a director of Orvana Minerals Ltd. and CCR Technologies Ltd. and a director of Matrikon Inc., Axia NetMedia Corporation and CanElson Drilling Ltd. At TransAlta, Mr. Jespersen is a member of the Governance and Environment Committee and the Human Resources Committee of the Board. Mr. Jespersen holds a bachelor of science in education and a master of science in education from the University of Oregon (Eugene, OR).
Michael M. Kanovsky Alberta, Canada	2004	***Corporate Director and Independent Businessman***. Mr. Kanovsky co-founded Northstar Energy Corporation (Northstar) with initial capital of $400,000 and helped build this entity into an oil and gas producer that was sold to Devon Energy Corporation for approximately $600 million in 1998. During this period, Mr. Kanovsky was responsible for strategy and finance as well as merger and acquisition activity. He initiated Northstar s entry into electrical cogeneration through its wholly-owned power subsidiary, Powerlink Corporation (Powerlink). Powerlink developed one of the first independent power producer (IPP) gas-fired co-generation plants in Ontario and also internationally. In 1997, he founded Bonavista Energy Trust, which has grown to a present day market capitalization of approximately $2 billion. Mr. Kanovsky is a director of Argosy Energy Corporation, ARC Energy Trust, Bonavista Energy Trust, Devon Energy Corporation, and Pure Technologies Ltd. At TransAlta, Mr. Kanovsky is a member of the Audit and Risk Committee and the Governance and Environment Committee of the Board. Mr. Kanovsky, a Professional Engineer, holds a bachelor of science in mechanical engineering from Queen s University (Kingston, ON) as well as a master of business administration from the Richard Ivey School of Business at the University of Western Ontario (London, ON).
Donna Soble Kaufman Ontario, Canada	1989	***Lawyer and Corporate Director***. Mrs. Kaufman is a former partner with Stikeman Elliott LLP, an international law firm, where she practised antitrust law. She has served on a number of boards since 1987, when she became a director of Selkirk Communications Limited, a diversified communications company. A year later she was appointed Chair of the Board, President and CEO. Several other directorships followed. In addition to TransAlta, Mrs. Kaufman currently serves on the boards of BCE Inc. and Bell Canada. She is also a director of HISTORICA, a private-sector education initiative, of the Institute of Corporate Directors, and a member of the Canadian Advisory Board of Catalyst, a non-profit organization working to advance women in business. In 2001, she was named a Fellow of the Institute of Corporate Directors. At TransAlta, Mrs. Kaufman is Chair of the Board and an ex-officio member of all committees of the Board.

Mrs. Kaufman holds a bachelor of civil law degree from McGill University (Montréal, QC) and a master of laws degree from the Université de Montréal (Montréal, QC).

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Gordon S. Lackenbauer (1) Alberta, Canada	2005	***Corporate Director***. Mr. Lackenbauer was Deputy Chairman of BMO Nesbitt Burns Inc. (investment banking) from 1990 to 2004. Prior to this, he was responsible for the principal activities of the firm, which included fixed income sales and trading, new issue underwriting, syndication and merger and acquisition advisory mandates. Mr. Lackenbauer has worked with many of Canada s leading utilities and has frequently acted as an expert financial witness testifying on the cost of capital, appropriate capital structure, and the fair rate of return, principally before the Alberta Utilities Commission, the National Energy Board, and the Ontario Energy Board. Mr. Lackenbauer is a director of NAL Oil & Gas Trust and CTV Globemedia Inc. At TransAlta, Mr. Lackenbauer is a member of the Governance and Environment Committee and the Audit and Risk Committee of the Board. Mr. Lackenbauer holds a bachelor of arts in economics from Loyola College (Montréal, QC), as well as a master of business administration from the University of Western Ontario (London, ON). He is also a chartered financial analyst.
Martha C. Piper British Columbia, Canada	2006	***Corporate Director***. Dr. Piper was President and Vice-Chancellor of the University of British Columbia from 1997 to 2006 (education). Prior to her appointment at UBC, she served as Vice-President, Research at the University of Alberta. She served on the boards of the Alberta Research Council, the Conference Board of Canada and the Centre of Frontier Engineering Research. Dr. Piper was also appointed by the Prime Minister of Canada to the Advisory Council on Science and Technology and currently Chairs the Board of the National Institute for Nanotechnology. Dr. Piper is a director of the Bank of Montreal, Shoppers Drug Mart Corporation and a member of the Canadian delegation to the Trilateral Commission, an organization fostering closer cooperation among the core democratic industrialized areas of the world. At TransAlta, Dr. Piper is a member of the Human Resources Committee and the Governance and Environment Committee of the Board. Dr. Piper holds a bachelor of science in physical therapy from the University of Michigan (Ann Arbor, MI), a master of arts in child development from the University of Connecticut (Storrs, CT), and a doctorate of philosophy in epidemiology and biostatistics from McGill University (Montréal, QC). She has also received honorary degrees from 16 international universities. Dr. Piper is an Officer of the Order of Canada and a recipient of the Order of British Columbia.
Luis Vázquez Senties Mexico	2001	***Corporate Director and Independent Businessman***. Mr. Vázquez is founder, President, CEO and Chairman of Grupo Diavaz, an international constructor of offshore oil and gas platforms, developer of oil and gas fields, and a distributor of natural gas in Mexico (oil and gas). Grupo Diavaz began as a Mexican underwater diving

operation that grew to become the world s second largest firm of its kind, servicing the offshore oil and gas industry in both exploration and production efforts.

Mr. Vázquez is Chairman of the Mexican Gas Association and Vice-President of the Mexico Chapter of the World Energy Council. He is a past director of the American Gas Association.

At TransAlta, Mr. Vázquez is a member of the Human Resources Committee of the Board.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Stephen G. Snyder Alberta, Canada	1996	***President and Chief Executive Officer of TransAlta Corporation since 1996.*** Previously Mr. Snyder was President & CEO, Noma Industries Ltd., President & CEO, GE Canada Inc., and President & CEO, Camco, Inc. Mr. Snyder is a director of the Canadian Imperial Bank of Commerce, Chair of the Calgary Stampede Foundation, and Chair of the Alberta Secretariat for Action on Homelessness. He is past-chair of the Calgary Committee to End Homelessness, the Canada-Alberta ecoEnergy Carbon Capture & Storage Task Force, the Conference Board of Canada, the Canadian Electricity Association, the Calgary Zoological Society, the University of Calgary Management Advisory Council, the Calgary Zoo Destination Africa Campaign and the Calgary United Way Campaign. Mr. Snyder holds a bachelor of science in chemical engineering from Queen s University (Kingston, ON) as well as a master of business administration from the University of Western Ontario (London, ON). He has honourary degrees from the University of Calgary (LLD), and the Southern Alberta Institute of Technology (Bachelor of Applied Technology). He was awarded the Alberta Centennial Medal in 2005, and the Conference Board Honorary Associate Award for 2008.

Notes:

(1) Mr. Bright served as a director of Access Air Inc. (Access Air) for the period of December 4, 1997 to January 31, 2000, a privately held start-up airline company. The company Mr. Bright was employed by, and whom he represented on the Access Air board, supported Access Air in the hope that it would improve air service to the state of Iowa. Access Air filed for bankruptcy protection on November 29, 1999.

(2) Mr. Lackenbauer resigned from the Board of Directors of Tembec Inc. (Tembec) on August 2, 2007. On December 19, 2007, Tembec announced its proposed recapitalization transaction providing a consensual solution to both noteholders and shareholders. On February 22, 2008, Tembec announced that it had received the approval of the majority of shareholders and the requisite majority of noteholders of Tembec Industries Inc. On February 27, 2008, Tembec announced that it had received approval from the Ontario Superior Court of Justice (Commercial List) with respect to their plan of arrangement relating to the proposed recapitalization transaction. On October 31, 2008, Tembec announced that it had successfully obtained a final American court order recognizing its Canadian plan of arrangement as a foreign proceeding in the United States.

Officers

Name	Principal Occupation	Residence
Stephen G. Snyder	President and Chief Executive Officer	Alberta, Canada
Brian Burden	Executive Vice-President and Chief Financial Officer	Alberta, Canada
William D.A. Bridge	Executive Vice-President, Generation Technology and PMM	Alberta, Canada
Dawn L. Farrell	Executive Vice-President, Commercial Operations and Development	Alberta, Canada
Richard P. Langhammer	Executive Vice-President, Generation Operations	Alberta, Canada
Kenneth S. Stickland	Executive Vice-President, Legal, SD and EH&S	Alberta, Canada
Michael Williams	Executive Vice-President, Human Resources, IT and Communications	Alberta, Canada
Frank Hawkins	Vice-President and Treasurer	Alberta, Canada
Maryse C. St.-Laurent	Corporate Secretary	Alberta, Canada

All of the officers of TransAlta have held their present principal occupation or position for the past five years, except for the following:

- Prior to December 2005, Brian Burden was Executive Vice-President and Chief Financial Officer of Molson Inc. Prior to 2002, he was Senior Vice-President, Seagram Corporate/Venture Transition of Diageo PLC.

- Prior to July 2007, William Bridge was Vice-President, Western Canada Operations. Prior to October 2005, Mr. Bridge was Vice-President, Customer and Asset Management; prior to September 2003, he was Vice-President, Development & Acquisition; and prior to September 2001 he was Director, Commercial Operations, Eastern Canada.

- Prior to July 2007, Dawn Farrell served as Executive Vice-President, Corporate Development, Executive Vice-President, Independent Power Projects and Vice-President, Energy Marketing and IPP Development at TransAlta Corporation. From 2003 to 2006, she served as Executive Vice-President Generation and in June 2006 she was appointed Executive Vice-President Engineering, Aboriginal Relations and Generation at B.C. Hydro.

- Prior to October 2005, Richard Langhammer was President, TransAlta Centralia Generation LLC and TransAlta Centralia Mining LLC, subsidiaries of the Corporation; and prior to December 2003, he was Vice-President, Plant Operations of TransAlta.

- Prior to April, 2007, Kenneth Stickland was Executive Vice-President, Legal.

- Prior to July 2007, Michael Williams was Executive Vice-President, HR & Communications.

- Prior to June 2007, Frank Hawkins was Assistant Treasurer.

- Prior to June 2005, Maryse St.-Laurent was Secretary of TC PipeLines, LP since September 2003 and Recording Secretary since January 2001, and Senior Legal Counsel TransCanada Corporation since June 1997.

As of March 11, 2009, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over an aggregate of 676,330 common shares of TransAlta. This constitutes less than one per cent of TransAlta s outstanding common shares.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Corporation, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10 per cent of the common shares of the Corporation, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving the Corporation within the three most recently completed financial years or to date in 2009 or in any proposed transactions that has materially affected or will materially affect the Corporation.

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2008, there has been no indebtedness, other than routine indebtedness, outstanding to TransAlta from any of TransAlta s directors, nominees for election as directors, executive officers, senior officers or associates of any such directors, nominees or officers.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders

Except as otherwise disclosed herein, no director, executive officer or controlling security holder of TransAlta Corporation is, as at the date of this Annual Information Form, or has been, within the past ten years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No director, executive officer or controlling security holder of TransAlta Corporation has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person s assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of TransAlta Corporation has:

(iv) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or

(v) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TransAlta is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Corporation s favour, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Corporation, taken as a whole, after taking into account amounts reserved by the Corporation. For further information, please refer to Notes 29 and 31 of the Corporation s audited consolidated financial statements for the year ended December 31, 2008, which financial statements are incorporated by reference herein. See Documents Incorporated by Reference herein.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for TransAlta s common shares is CIBC Mellon Trust Company in Vancouver, Calgary, Winnipeg, Toronto and Montreal. The transfer agent and registrar for the common shares in the United States is Mellon Investor Services LLC at its principal office in New York, New York.

INTERESTS OF EXPERTS

Ernst & Young LLP, Chartered Accountants, 1000, 440 - 2nd Avenue, S.W., Calgary, Alberta, T2P 5E9 are the auditors of the Corporation.

TransAlta s auditors, Ernst & Young LLP, are independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and have complied with the SEC s rules on auditor independence.

ADDITIONAL INFORMATION

Additional information in relation to TransAlta may be found under TransAlta s profile on SEDAR at www.sedar.com.

Additional information including directors and officers remuneration and indebtedness, principal holders of TransAlta s securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained in TransAlta s Management Proxy Circular for its most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from the Corporate Secretary of TransAlta Corporation.

Additional financial information is provided in TransAlta s audited consolidated financial statements as at and for the year ended December 31, 2008 and in the Annual MD&A, each of which is incorporated by reference in this Annual Information Form. See Documents Incorporated by Reference herein.

AUDIT AND RISK COMMITTEE

General

The members of TransAlta s Audit and Risk Committee (**ARC**) satisfy the requirements for independence under the provisions of Canadian Securities Regulators, Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange Rules and Rule 10A-3 under the U.S. Securities and Exchange Act of 1934. The ARC s Charter requires that it be comprised of a minimum of three independent directors. It currently has six independent members, William D. Anderson (Chair), Stephen L. Baum, Timothy W. Faithfull, Michael M. Kanovsky, Gordon S. Lackenbauer and Donna S. Kaufman as an ex-officio member. All members of the committee are financially literate pursuant to both Canadian and U.S. securities requirements and each of Mr. William D. Anderson and Mr. Gordon S. Lackenbauer have been determined by the Board to be an *audit committee financial expert* , within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 (**Sarbanes-Oxley Act**).

Mandate of the Audit and Risk Committee

The mandate of the ARC is to assist the Board in its oversight responsibility to the shareholders of the Corporation, the investment community and others relating to the integrity of the Corporation s financial statements, the quality of its financial reporting processes, the systems of internal accounting and financial controls, the risk identification assessments conducted by management and the programs established in response to such risks, the internal audit function, the external auditors qualifications, independence, performance and reports and to provide oversight with respect to legal compliance programs established by management which may have a material effect on the financial statements of the Corporation. The ARC also reviews the Corporation s compliance with the Corporation s code of conduct, financial code of conduct and the Corporation s policy with respect to the hiring of employees of the external auditors.

The ARC s function is oversight. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation. Management and the internal audit group of the Corporation are responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures for compliance with accounting standards and applicable laws and regulations.

While the ARC has the responsibilities and powers set forth herein, it is not the duty of the ARC to plan or conduct audits or to determine that the Corporation s financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors.

Management is responsible for preparing the interim and annual financial statements and financial disclosure of the Corporation and for maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly. The ARC s role is to provide direct, meaningful and effective oversight of the Corporation s financial reporting and counsel to management without assuming responsibility for management s day to day duties.

Audit and Risk Committee Charter

The Charter of the Audit and Risk Committee is attached as Appendix A .

Relevant Education and Experience of Audit and Risk Committee Members

The following is a brief summary of the education or experience of each member of the ARC that is relevant to the performance of their responsibilities as a member of the ARC, including any education or experience that has provided the member with an understanding of the accounting principles used by TransAlta to prepare its annual and interim financial statements.

Name of ARC Member	Relevant Education and Experience
W. D. Anderson	Mr. Anderson is a Chartered Accountant. Mr. Anderson has served as Chief Executive Officer of a public company and as Chief Financial Officer of several public companies. In such capacities, Mr. Anderson actively supervised persons engaged in preparing, auditing, analyzing or evaluating financial statements. Mr. Anderson has also served as a principal financial officer and accounting officer and as a director and audit committee member of several public companies.

Stephen L. Baum	Mr. Baum has over 25 years of financial, legal and industry experience gained working as a senior officer, director and Chairman of energy companies. During his tenure as CEO of Sempra Energy, Mr. Baum had financial officers reporting directly to him. Mr. Baum also serves as Chairman of the Audit Committee of Computer Sciences Corporation, a NYSE listed company. Mr. Baum holds a law degree from the University of Virginia.
T. W. Faithfull	Mr. Faithfull holds a Bachelor of Arts degree in Economics and has acquired significant financial experience and exposure to accounting and financial issues as Chief Executive Officer of Shell Canada Limited and in his other capacities during his 36 years with the Royal Dutch/Shell group of companies.
M. M. Kanovsky	Mr. Kanovsky has over 30 years of financial and industry experience gained through working in the investment banking business as well as a director, officer and audit committee member of several public companies and trusts. Mr. Kanovsky is a graduate of the MBA program from the Richard Ivey School of Business at the University of Western Ontario.

Name of ARC Member	Relevant Education and Experience
G. S. Lackenbauer	Mr. Lackenbauer has over 35 years of experience in the investment banking industry. Mr. Lackenbauer has also appeared as an expert financial witness with respect to financial markets, capital structure, cost of capital and fair return on common equity, in over 40 regulatory proceedings. Mr. Lackenbauer also has extensive experience as a director or governor of public companies and not-for-profit organizations. Mr. Lackenbauer holds a Bachelor of Arts in Economics, a MBA degree from the University of Western Ontario and is a Chartered Financial Analyst.
D. S. Kaufman (ex-officio)	Mrs. Kaufman has over 25 years of legal, professional and financial management experience gained in the practice of law, as a director of several public companies and as Chair, President and CEO of Selkirk Communications. Mrs. Kaufman has served on several audit committees. Mrs. Kaufman holds a civil law degree from McGill University and a master of laws from the University of Montreal.

Other Board Committees

In addition to the Audit and Risk Committee, TransAlta has two other standing committees: the Governance and Environment Committee and the Human Resources Committee. Mrs. Kaufman, the Chair of the Board, is a non-voting ex-officio member of all committees. The members of these committees as of December 31, 2008 are:

Governance and Environment Committee

Chair: Ambassador Gordon D. Giffin
C. Kent Jespersen
Michael M. Kanovsky
Gordon S. Lackenbauer
Dr. Martha C. Piper
Donna Soble Kaufman (ex-officio)

Human Resources Committee

Chair: Stanley J. Bright
Stephen L. Baum
Timothy W. Faithfull
C. Kent Jespersen
Dr. Martha C. Piper
Luis Vázquez Senties
Donna Soble Kaufman (ex-officio)

The Charters of the Governance and Environment Committee and the Human Resources Committee may be found on TransAlta s website under Corporate Responsibility - Governance at www.transalta.com. Further information about the Board and the Corporation s corporate governance may also be found on our website or in the Corporation s Management Proxy Circular which is filed on Sedar at www.sedar.com.

Fees Paid to Ernst & Young LLP

For the years ended December 31, 2008 and December 31, 2007, Ernst & Young LLP and its affiliates were paid $3,372,142 and $2,838,740 respectively, as detailed below:

Year ended Dec. 31

Ernst & Young LLP		2008		2007
Audit fees	$	2,594,183	$	2,624,029
Audit related fees		432,343		168,968
Tax fees		345,616		45,743
Total	**$**	**3,372,142**	**$**	**2,838,740**

No other audit firms provided audit services in 2008 or 2007.

The nature of each category of fees is described below:

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of the Corporation s annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English to French of the Corporation s financial statements and other documents. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923. Total audit fees for 2007 include payments related to 2006 in the amount of $1,476,300.

Audit-Related Fees

The audit-related fees in 2008 were primarily for work performed by Ernst & Young LLP in relation to miscellaneous accounting advice provided to the Corporation.

Tax Fees

Majority of tax fees for 2008 relate to the finalization of tax credit recoveries.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors independence. In May 2002, the ARC adopted a policy that prohibits TransAlta from engaging the auditors for prohibited categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act.

Representatives of Ernst & Young LLP will be in attendance at the Meeting, will have the opportunity to make a statement if they so wish and will be available to respond to questions.

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APPENDIX A

TRANSALTA CORPORATION

(the Corporation)

AUDIT AND RISK COMMITTEE CHARTER

A. Establishment of Committee and Procedures

1. Composition of Committee

The Audit and Risk Committee (the Committee) of the Board of Directors (the Board) of TransAlta Corporation (the Corporation) shall consist of not less than three Directors. All members of the Committee shall be determined by the Board to be independent as required under the provisions of Canadian Securities Regulators Multilateral Instrument 52-110 Audit Committees, Section 303A of the New York Stock Exchange rules and Rule 10A-3 of the U.S. Securities and Exchange Act of 1934, as such rules apply to audit committee members. All members of the Committee must be financially literate pursuant to both Canadian and U.S. securities requirements and at least one member must be determined by the Board to be an audit committee financial expert within the meaning of Section 407 of the United States Sarbanes-Oxley Act of 2002 (the Sarbanes Oxley Act). Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the Board of Directors (the Board) at the recommendation of the Committee.

2. Appointment of Committee Members

Members of the Committee shall be appointed from time to time by the Board, on the recommendation of the Governance and Environment Committee, and shall hold office until the next annual meeting of shareholders, or until their successors are earlier appointed, or until they cease to be Directors of the Corporation.

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

4. Committee Chair

The Board shall appoint a Chair for the Committee on the recommendation of the Governance and Environment Committee.

5. Absence of Committee Chair

If the Chair of the Committee is not present at any meeting of the Committee, one of the members of the Committee who is present at the meeting shall be chosen by the Committee to preside at the meeting.

6. Secretary of Committee

The Committee shall appoint a Secretary who need not be a director of the Corporation.

7. Meetings

The Chair of the Committee or any of its members may call a meeting of the Committee. The Committee shall meet at least quarterly and at such other time during each year as it deems appropriate. In addition, the Chair of the Committee or any of its members may call a special meeting of the Committee at any time. Although the Corporation s Chief Executive Officer may attend meetings of the Committee, the Committee shall also meet in separate executive sessions.

8. Quorum

A majority of the members of the Committee present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak to each other, shall constitute a quorum.

9. Notice of Meetings

Notice of the time and place of every meeting shall be given in writing (including by way of written facsimile communication or email) to each member of the Committee at least 48 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive notice of a meeting; and attendance of a member at a meeting constitutes a waiver of notice of the meeting, except where a member attends for the express purpose of objecting to the transaction of any business on the ground that the meeting is not lawfully called. Notice of every meeting shall also be provided to the external and internal auditors.

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members, officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board generally not later than the next scheduled meeting of the Board.

12. Review of Charter

The Committee shall evaluate its performance and review and reassess the adequacy of its Charter at least annually or otherwise, as it deems appropriate, and if necessary propose changes to the Governance and Environment Committee and the Board for review and approval.

13. Outside Experts and Advisors

The Committee Chair, on behalf of the Committee, or any of its members is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter.

B. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibility to the shareholders, the investment community and others, relating to the integrity of the Corporation s financial statements, the financial reporting process, the systems of internal accounting and financial controls, the risk identification assessment conducted by management and the programs established by management and the Board in response to such assessment, the internal audit function and the external auditors qualifications, independence, performance and reports to the Corporation. In so doing, it is the Committee s responsibility to maintain an open avenue of communication between the Committee, the external auditors, the internal auditors and management of the Corporation.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the interim and annual financial statements and related disclosure documents. Management of the Corporation is also responsible for maintaining appropriate accounting and financial reporting policies and systems of internal controls and procedures that are in compliance with accounting standards, applicable laws and regulations and that provide reasonable assurances that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly.

While the Committee has the responsibilities and powers set forth herein, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation s financial statements are complete and accurate and in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors. The designation of a member or members as an audit committee financial expert is based on that individual s education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an *audit committee financial expert* does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on a member of the Committee and Board in the absence of such designation.

Management is also responsible for the identification and management of the Corporation s risks and the development and implementation of policies and procedures to mitigate such risks. The Committee s role is to provide oversight in order to ensure that the Corporation s assets are protected and safeguarded within reasonable business limits.

C. Duties and Responsibilities of the Committee

The Committee shall have the following specific duties and responsibilities:

1. Audit and Financial Matters

The Committee shall:

(a) have direct responsibility for the compensation and oversight of the external auditors including nominating the external auditors to the Board for appointment by the shareholders at the Corporation s general annual meeting. In performing its function, the Committee shall:

(i) review the experience and qualifications of the external auditors senior personnel who are providing audit services to the Corporation and the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S. regulatory registration requirements;

(ii) review and approve annually the external auditors audit plan;

(iii) review and approve the basis and amount of the external auditors fees and ensure the Corporation has provided appropriate funding for payment of compensation to the external auditors;

(iv) review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors independence, including, without limitation, (i) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors report to satisfy itself of the external auditors independence;

(v) resolve disagreements between management and the external auditors regarding financial reporting;

(vi) pre-approve all audit related services including all non-prohibited non-audit services provided by the external auditors; the Chair of the Committee, is authorized to approve all audit related services including non-prohibited non-audit services provided by the external auditors, and shall report all such approvals to the Committee at its next scheduled meeting;

(vii) inform the external auditors and management that the external auditors shall have direct access to the Committee at all times, as well as the Committee to the external auditors; and

(viii) instruct the external auditors that they are ultimately accountable to the Committee as representatives of the shareholders of the Corporation;

(b) review with management and the Corporation s external auditors the Corporation s financial reporting in connection with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation s accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation s accounting principles and underlying estimates;

(c) review with management and the external auditors all financial statements and financial disclosure;

(i) recommend to the Board for approval the Corporation s audited annual financial statements including the notes thereto and, Management s Discussion and Analysis ;

(ii) review any report or opinion to be rendered in connection therewith;

(iii) review with the external auditors the cooperation they received during the course of their review and their access to all records, data and information requested;

(iv) discuss with management and the external auditors all significant transactions which were not a normal part of the Corporation s business;

(v) review the management processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(vi) review with management and the external auditors any changes in accounting principles and their applicability to the business;

(vii) review with management and the external auditors alternative treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditors;

(viii) satisfy itself that there are no unresolved issues between management and the external auditors that could reasonably be expected to materially affect the financial statements;

(d) review with management and the external auditors the Corporation s interim financial statements, including the notes thereto, Management s Discussion and Analysis and earnings release, and approve the release thereof by management to the public;

(e) review and discuss with management and external auditors the use of pro forma or adjusted non-GAAP information and the applicable reconciliation;

(f) on behalf of the Committee, the Chair shall review all public disclosure of material financial information extracted or derived from the Corporation s financial statements;

(g) review with management at least annually the approach and nature of financial information and earnings guidance to be disclosed to analysts and rating agencies;

(h) review and recommend to the Board for approval the Corporation s issuance and redemption of securities, financial commitments and limits, and any material changes underlying any of these commitments;

(i) at least annually, obtain and review the external auditors report with respect to the auditing firm s internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the auditing firm, any inquiry or investigation by governmental or professional authorities within the preceding five years undertaken respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues;

(j) review quarterly with senior management, the chief legal officer and, as necessary, outside legal advisors, and the Corporation s internal and external auditors, the effectiveness of the Corporation s internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and with the Corporation s policies;

(k) review quarterly with the chief legal officer, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the financial statements of the business;

(l) review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with management s response thereto;

(m) review changes in accounting practices or policies and the financial impact these may have on the Corporation;

(n) discuss with the external auditors their perception of the Corporation s financial and accounting personnel, any recommendations which the external auditors may have, including those contained in the management letter, with respect to improving internal financial controls, choice of accounting principles or management reporting systems, and review all management letters from the external auditors together with management s written responses thereto;

(o) review with management, the external auditors and, as necessary, internal and external legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(p) review annually the Annual Pension Report and financial statements of the Corporation s pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs;

(q) together with the Human Resources Committee of the Board, review annually and as required the overall governance of the Corporation s Pension Plans, approve the broad objectives of the plans and report to the Board annually;

(r) review annually the internal audit department s charter, the scope and plans for the work of the internal audit group the adequacy of the group s resources, the internal auditors access to all functions, records, property and personnel of the Corporation and inform the internal auditors and management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(s) meet separately with management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(t) review the annual audit of expense accounts and perquisites of the Directors, the CEO and his direct reports, including the use of the Corporation s assets, as well as the Corporation s annual sponsorship, donations and political contributions;

(u) review management s processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud and the process put in place for monitoring the risks within targeted areas;

(v) review with the Corporation s senior financial management and the Vice-President Internal Audit the adequacy of the Corporation s systems of internal control and procedures;

(w) review disclosures made to the Committee by the CEO and Chief Financial Officer (the CFO) during their certification process for the relevant periodic reports filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation s disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving management or other employees who have a significant role in the Company s internal controls was reported to the Committee;

(x) ensure that the Corporation s business practices and ethical behaviours are communicated to employees and contractors on an annual basis, to review at least annually the Corporate Code of Conduct and the policies and practices in place to ensure compliance. Inquire of the internal and external auditors as to any instances of deviation from the Corporate Code of Conduct which has come to their attention and the action taken as a result of same;

(y) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding accounting or auditing matters;

(z) review all incidents, complaints or information reported through the Ethics Help Line and/or management;

(aa) review disclosure made to the Committee by the chief executive officer, chief financial officer and/or chief legal officer of a material violation of applicable securities laws, a material breach of a fiduciary duty under applicable laws or a similar material violation by the Corporation or by any officer, director, employee or agent of the Corporation, which has been reported to the Committee, determine whether an investigation is necessary regarding any such report and report to the board;

(bb) discuss with management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation s financial statements or accounting policies;

(cc) report annually to shareholders or on the work of the Committee during the year;

(dd) review and approve the Corporation s hiring policies for employees or former employees of the external auditors and monitor the Corporation s adherence to the policy;

(ee) recommend to the Human Resources Committee the appointment and termination or transfer of the Vice-President, Internal Audit.

2. <u>Risk Management</u>

The Committee provides oversight of management s establishment of an overall risk culture for the Corporation. The Committee shall oversee and approve the processes established and developed by management for the identification of the Corporations principal risks, the evaluation of potential impact and the implementation of appropriate systems to mitigate and manage the risks.

The Committee shall:

(a) review annually with the Board management s assessment of the significant risks to which the Corporation is exposed; discuss with management the Corporation s policies and procedures for identifying and managing the principal risks of its business in order to ensure that management:

(i) has identified appropriate business strategies taking into account the principal risks identified, and

(ii) is maintaining systems and procedures to manage or mitigate those risks, including programs of loss prevention, insurance and risk reduction and disaster response and recovery programs;

(b) receive and review managements quarterly risk assessment update including an update on residual risks, emergent risks and next steps;

(c) review the Corporation s enterprise risk management framework and reporting methodology;

(d) review annually the Corporation s Financial and Commodity Exposure Management Policies and approve changes to such policies; review and authorize strategic hedging program guidelines and risk tolerance; review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(e) review the Corporation s annual insurance program, including the risk retention philosophy and resulting uninsured exposure and corporate liability protection programs for directors and officers including directors and officers insurance coverage;

(f) periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external counsel concerning risk management of the Corporation and review their performance in relation to such roles and responsibilities; and

(g) annually, together with management report to the Board on:

(i) the Corporation s strategies in light of the overall risk profile of the Corporation;

(ii) the nature and magnitude of all significant risks;

(iii) the processes, policies, procedures and controls in place to manage or mitigate the significant risks; and

(iv) the overall effectiveness of risk management processes including highlighting risk management problems and the actions that have been or will be taken to address them.

D. Compliance and Powers of the Committee

(a) The responsibilities of the Committee complies with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition this Charter complies with the applicable US laws, such as the Sarbanes-Oxley Act, and the rules and regulations adopted thereunder, and with the New York Stock Exchanges corporate governance standards, as they exist on the date hereof. This Charter is reviewed from time to time by the Corporate Secretary together with the Chair of the Committee in order to ensure on going compliance with such standards.

(b) The Committee may, at the request of the Board or on its own initiative, investigate such other matters as are considered necessary or appropriate in carrying out its mandate.

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APPENDIX B

GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

AEUB means the Alberta Energy and Utilities Board;

Alberta PPA means an Alberta government mandated power purchase arrangement;

availability means the weighted average equivalent availability factor , which is a term used to calculate availability for a pool or fleet of units of varying sizes. It is a measure of time and energy expressed in percentage of continuous operation, 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, whether or not it is actually generating electricity;

capacity means net maximum capacity that a unit can sustain over a period of time;

gigawatt hour or **GWh** means one million kilowatt hours of electrical power;

kilowatt or **kW** means 1,000 watts of electrical power;

kilowatt hour or **kWh** means one hour during which one kilowatt of electrical power has been continuously produced;

megawatt or **MW** means 1,000 kilowatts or one million watts of electrical power;

megawatt hour or **MWh** means 1,000 kilowatt hours;

PPA means a power purchase agreement having an initial term of five years or greater;

watt means the scientific unit of electrical power, being the rate of energy use that gives rise to the production of energy at a rate of one joule per second;

watt hour is a measure of energy production or consumption equal to one watt produced or consumed for one hour; and

WPPI means the Government of Canada s Wind Power Production Incentive available to approved wind generation facilities commissioned between April 1, 2002 and March 31, 2007.

Management 's Discussion and Analysis

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This management's discussion and analysis ("MD&A") should be read in conjunction with the audited 2008 consolidated financial statements. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All dollar amounts in the following discussion including the tables are in millions of Canadian dollars unless otherwise noted. This MD&A is dated March 4, 2009. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including its annual information form, is available on SEDAR at www.sedar.com and on our website at www.transalta.com.

Business Environment

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

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

Demand

Demand for electricity is a fundamental driver of prices in all of our markets. Economic growth is the key driver of longer-term changes in the demand for electricity. Demand for electricity in all three of our major markets has been growing at an average rate of one to three per cent per year; however, the current weak economic environment is potentially threatening growth in demand. Alberta has seen the highest rate of growth in demand in recent years, driven by a strong economy. However, development of the oil sands is starting to slowdown as oil sands developers delay and cancel projects. Since a significant portion of Alberta's electricity load is industrial, a slowdown in the oil sands development sector will likely affect overall demand growth. While declines in demand growth over the next few years are not expected to impact us significantly as a result of our highly contracted capability, a more significant decline in the rate of demand growth could occur between 2013 and 2018, when the majority of the delayed and cancelled oil sands projects were scheduled to begin operations. In the Pacific Northwest, demand has grown at a moderate but steady pace but may be threatened due to a recessionary environment in the nearer-term. Demand in Ontario is expected to remain relatively weak, due to reduced manufacturing activity and conservation.

Supply

In all markets in which we operate, the cost of building new generating capacity has increased due to a shortage of component parts and the increased cost of raw materials. We are seeing indications that many North American power companies are postponing the construction of projects or cutting 2009 capital spending. We believe that reserve margins, which are the amount of generating capacity available in excess of the capacity needed to meet normal demand levels, will continue to contract and, as a result, prices are expected to remain fairly strong over the longer-term. In the nearer-term, reserve margins are expected to increase due to weaker economic conditions and new supply coming on stream. Overall, significant changes in investment patterns are expected to increase the volatility in the price of both natural gas and electricity.

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

Transmission

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

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

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

Environmental Legislation and Technologies

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

Both the Canadian and U.S. federal governments are considering cap and trade policies to manage greenhouse gas emissions. However, economic uncertainty fueled by financial market volatility, a developing recession, and Canada's political environment may delay the adoption of such systems. For these reasons, the government in Canada may not implement new environmental legislation until 2010 or later. In the U.S. the Western Climate Initiative ("WCI"), a group of eleven U.S. western states and Canadian provinces unveiled its final version of a cap and trade plan in 2008. Washington State, where our Centralia Thermal plant ("Centralia Thermal") is located, is a member of this group. The regional goal from this initiative is to reduce GHG emissions by 15 per cent below 2005 levels by 2020. Separately, Washington State is also considering its own climate change legislation that could be implemented independently or in coordination with the WCI program.

These initiatives will impact any decision to construct new coal-fired facilities in the region because growth will increase overall emissions and compliance costs. Additional growth would result in a need for alternative energy resources and carbon offsets to be investigated, and those investments could lead to an overall increase in compliance environmental spending. Refer to the Climate Change and Air Emissions section of this MD&A for further details.

While carbon capture and storage ("CCS") technologies are being developed, these technologies are not sufficiently advanced at this time. Consequently, we are expecting environmental compliance costs to increase the cost of generating electricity so long as they are in place and/or the cost of low carbon generation technologies are higher than high carbon generation technologies.

Economic Environment

As a result of the current economic environment, commodity prices, other than electricity, are decreasing. In the short-term, lower commodity prices, specifically natural gas and coal, will not significantly alter our operating costs because those input costs have been contracted. The decrease in commodity prices could result in lower operating costs for us in the future if commodity prices remain low and we can contract at those lower prices. In addition, decreasing commodity prices have begun to lower the price of assets owned by others, which could result in cost-efficient acquisitions to further diversify our portfolio of assets.

A number of financial and industrial counterparties have experienced credit rating downgrades and we expect 2009 will continue to be a challenging year for some of our counterparties as a result of the recent financial crisis and current economic environment. While we had no counterparty losses in 2008, we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties in our trading and hedging activities.

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

Electricity Prices

Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability as well as any contracting strategy. Our Alberta plants operating under PPAs pay penalties or receive payments based upon a rolling 30-day average of spot prices. Longer-term contracts at Centralia Thermal and Sarnia and our shorter-term contracts at Genesee 3 and Wabamun minimize the impact of spot price changes.

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

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

For the year ended Dec. 31, 2008, spot prices increased in Alberta and the Pacific Northwest and were essentially flat in Ontario compared to the same period in 2007. Alberta spot prices increased due to higher natural gas prices during the first three quarters of 2008, higher production losses due to higher than normal forced and planned outages, and lost production as a result of transmission system upgrades. The Pacific

Northwest spot prices increased primarily due to higher natural gas prices during the first three quarters of 2008. Ontario spot prices were relatively unchanged, with higher natural gas prices being offset by increased hydro generation.

Fuel Costs

Our generating facilities use either renewable fuel sources such as water, wind, or geothermal or use combustible fuels such as coal and natural gas. The costs of these fuels, including the cost to supply them to our generating facilities, affect our financial results. With the current market conditions, we are generally seeing falling commodity prices, but coal costs are expected to continue to increase due to higher contract and transportation costs. As a result, coal costs at Centralia Thermal are expected to increase 10 to 15 per cent in 2009.

Mining coal in Alberta is subject to cost increases due to increased overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal mining are minimized through the application of standard costing. Coal costs for 2009, on a standard cost basis, are expected to increase five per cent from the prior year primarily due to increased capital expenditures.

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

The previously announced construction of numerous liquefied natural gas ("LNG") terminals throughout North America was expected to significantly impact the natural gas market by allowing for large amounts of natural gas shipments to occur between continents. These terminals would have created an international market of supply and demand, which could have significantly impacted natural gas prices. However, with the recent economic environment, decreasing commodity prices and the supply of natural gas that currently exists in North America, the construction of the majority of the planned LNG terminals has been delayed or cancelled due to higher than anticipated construction costs and insufficient returns. Accordingly, this technology is not expected to have a significant impact on natural gas prices in the near future.

In 2008, the amount of natural gas production in North America from unconventional sources, such as shale gas, has increased. If shale gas production is sustainable and economically viable over the long-term, this increased production from unconventional sources could potentially reduce the price of natural gas over the longer-term.

We closely monitor the risks associated with changes in electricity and natural gas prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risk.

Spark Spreads

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

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

Using this standardized measure, the average spark spreads in each of the past three years in our three main markets are shown in the adjacent graph.

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

For the year ended Dec. 31, 2008, spark spreads increased in Alberta and decreased in the Pacific Northwest and Ontario compared to the same period in 2007. Alberta spark spreads were higher due to increased planned and unplanned outages. Spark spreads in the Pacific Northwest were lower due to increased hydro generation during the second quarter of 2008. In Ontario, spot spark spreads were lower due to increased hydro generation, partially offset by higher natural gas prices.

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

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

Strategy

Our strategic position is to deliver shareholder value by maintaining a low-to-moderate risk profile, which is centered around long-term comparable earnings per share ("EPS") growth driven by geographically focusing our operations and expanding our portfolio in the western regions of Canada and the U.S. We are focusing on this geographic area because of market dynamics, such as deregulation, demand growth and potential green energy growth, and our expertise, scale, and access to numerous fuel resources, including coal, wind, geothermal, hydro and natural gas.

Financial Strategy

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

Contracting Cash Flows

In Alberta, demand was almost flat in 2008 compared to the growth experienced in 2007, primarily due to the delayed start-up of several large industrial projects. In 2009, while we do expect some growth in demand in Alberta due to these delayed projects coming online, we expect that demand growth will be softer than initially forecasted. While we will not be immune to softening power prices, the impact is significantly mitigated because across our fleet approximately 90 per cent of 2009 and approximately 85 per cent of 2010 expected capacity is contracted. It is this low-to-moderate risk contracting strategy that helps protect our cash flow and our balance sheet through economic cycles and will ultimately help us through the current downturn in the market.

Growth Strategy

The time frame for delivering on the growth component of our strategy is outlined below.

Short-Term: 2009 2012

During this period, the focus will be on efficiency uprates at our Keephills and Sundance facilities and growing renewable energy capacity, such as wind and geothermal. We will continue our research related to various emission reduction technologies and projects, such as CCS technology and carbon dioxide ("CO_2") offsets. Our focus will be on renewable energy during this time frame until we determine if CCS technology will be economically viable prior to building more coal-fired facilities.

Medium-Term: 2013 2015

During this period, the focus of our strategy will shift to the construction of CCS technologies and investment in the life cycle of our Alberta Thermal plants ("Alberta Thermal") to improve the longer-term efficiency and availability of our facilities. Potential investments in alternative energy sources that have not been traditional growth areas for us, such as hydro, will be investigated along with continued investment in CO_2 offsets.

Longer-Term: Beyond 2016

During this period, our strategy will be to increase overall capacity without increasing our emissions profile. Construction of current growth and emission reduction projects will be completed and in full production, potentially including coal-fired plants with CCS technology. We anticipate having generating assets using alternative energy to be compliant with the expected increase in environmental regulations. This growth could be achieved by partnering with a large hydro operation, potentially obtaining an equity share in alternate energy projects, and/or uprating the capacity of existing facilities.

Capability to Deliver Results

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

Portfolio Optimization

We seek to optimize our generating portfolio by owning and managing a mix of assets aimed at providing the highest return for a relatively low level of risk. This optimization requires that we divest or improve returns from our non-core and underperforming assets. Most recently, we sold our Mexico operations and we are currently pursuing an improved long-term contract at Sarnia. In 2009, we will perform upgrades on the gas turbine engines at our Ottawa, Mississauga and Windsor facilities to improve productivity and enhance returns.

Financial Strength

We carefully manage our balance sheet in order to maintain financial strength and flexibility throughout all economic cycles. This discipline is important in the current economic environment. We currently maintain financial ratios that exceed our minimum targets. We continue to maintain $2.2 billion available in committed credit facilities, and as of Dec. 31, 2008, $1.4 billion was available to us. These strong ratios, available credit, and continued positive cash flow from operations provide us with ample financial flexibility and as a result, we can be selective about if and when we go to the capital markets for funding.

Environmental Leadership

We are committed to being industry leaders in environmental stewardship. In the past, we have been involved in various projects directed toward researching and implementing more environmentally friendly technologies at our plants. In April 2008, we announced Project Pioneer that will pilot Alstom Canada's chilled ammonia CCS technology at one of our Alberta Thermal units. This technology has the potential to remove up to 90 per cent of CO_2 emissions. This CCS project will be the largest of its kind and the first project in the world to have an integrated underground storage system. TransCanada PipeLines Limited is participating in the development of Project Pioneer and we are working to secure additional industry partners. Securing industry partners and funding initiatives from the federal and provincial governments are key to accelerating CCS projects across Alberta.

In 2007, we voluntarily installed continuous emissions monitoring systems at Centralia Thermal. In 2008, we reached an agreement with the Department of Ecology in Washington State to voluntarily cut emissions of mercury and visibility-limiting nitrogen oxide. Testing and certification of these new technologies occurred throughout 2008 and will continue into the future. We continue to work with regulators to determine appropriate reduction targets and compliance timelines and to develop future environmental policy. We remain dedicated to being involved in discussions with policy-makers and regulators regarding future environmental legislation and implementation.

Disciplined Capital Allocation

We are committed to optimizing the balance between dividend growth, liquidity requirements, base business investment, growth opportunities, and share buybacks. We have a proven track record of long-term financial stability and are committed to paying dividends to shareholders based on between 60 and 70 per cent of comparable earnings.[1]

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Comparable earnings is not defined under Canadian GAAP. Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of comparable earnings, including a reconciliation to net earnings.

We continue to grow our diversified generating fleet in order to increase production and meet future demand requirements, with all growth projects having to exceed corporate hurdles for returns. We currently have 456 megawatts ("MW") of capacity under construction and due to be commissioned in the 2009-2012 period, which is comprised of 225 MW of coal-fired generation, 99 MW of uprates to our thermal coal fleet, and 132 MW of wind power. We are a leading generator of wind power in Canada and these growth projects will increase our total renewable energy capacity.

In addition to our greenfield growth plans, we continue our uprates of existing facilities. These uprates add capability to our existing fleet and provide opportunities for high rates of return.

Lifecycle Planning

Managing the operation and maintenance of our fleet is important to ensure reliable generation and revenues. Ensuring the consistent reliability of our facilities is achieved by understanding current technologies and monitoring new developments in technology for their potential application. Lifecycle planning also involves making decisions as to when changes should be made to our existing facilities and when maintenance should occur on components at those facilities. Our success in providing reliable generation is a result of carefully planned and closely monitored maintenance schedules, as well as efficient response and correction of unplanned outages at our facilities. We expect to see increases in production over time as we continue to optimize our current major and routine maintenance programs.

Operational Excellence

We achieve operational excellence by closely planning and monitoring the routine maintenance requirements of our assets. Over the last five years, our average availability has been 88.1 per cent, which is below our corporate target of 90 to 92 per cent. This decrease in our average availability has been primarily impacted by the declines in availability in 2007 and 2008 due to higher than normal unplanned outages at our plants. A significant portion of these unplanned outages were a result of boiler leaks at our Alberta Thermal facilities.

While Alberta Thermal faced challenges in 2008, we have a solid plan to drive our fleet to 90 to 92 per cent availability. We realize that there is always going to be a trade-off between costs and availability and that there are always going to be operational risks that cannot be entirely eliminated economically. We acknowledge the challenges that were faced in 2008 and have refined our understanding of the business risks and the relationship to maintenance work related to these challenges. Part of our plan to address the boiler leaks at our Alberta Thermal facilities includes a heavy maintenance schedule for 2009, for which the majority of the work is scheduled to take place in the first and second quarters.

In addition, part of our plan to improve availability was implementing the Operations Diagnostic Centre ("ODC"), which came online on Dec. 1, 2008. The ODC is a real-time monitoring centre staffed by highly trained engineers and operators. It uses state-of-the-art technology to enable us to optimize our preventive maintenance work by allowing us to continuously monitor and improve our operation. The ODC is instrumental to improving the efficiency of our generating fleet by enabling us to monitor the entire fleet in one location and to plan and act on a fleet-wide basis, instead of on a somewhat isolated plant-level scale. We believe the investment in the ODC will pay for itself in two years.

We have performed significant planned maintenance work to improve availability and efficiency at Centralia Thermal by modifying the boilers to burn Powder River Basin ("PRB") coal. We completed the Unit 2 boiler modifications, a 500,000-man-hour turnaround, on time and with an excellent safety record. Unit 2 is operating to all performance targets. Unit 1 boiler modifications are scheduled to begin in the spring of 2009.

We will continuously monitor and revise our plans, as necessary, to improve availability and to meet our corporate targets.

Organizational Leadership

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

Performance Metrics

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

Availability

Our plants must be available throughout the year at all times to meet demand. However, this ability to meet demand is limited by the requirement to shut down for planned maintenance and unplanned outages, and reduced production as a result of derates. Our goal is to minimize these events through regular assessments of our equipment and a comprehensive review of our maintenance plans. Over the past three years we have achieved an average availability of 87.3 per cent, which is below our long-term target of 90 to 92 per cent. Our availability in 2008 was 85.8 per cent. The graph above shows our availability results for the past three years.

Availability for the year ended Dec. 31, 2008 decreased to 85.8 per cent from 87.2 per cent compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher planned outages as a result of equipment modifications at Centralia Thermal, partially offset by lower derates at Centralia Thermal as in 2007 we conducted test burns of PRB coal.

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

Production

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

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

In 2007, production increased 2,182 GWh compared to the same period in 2006 due to higher production at Centralia Thermal and lower planned outages and increased demand at Sarnia partially offset by higher unplanned outages at Alberta Thermal.

Productivity

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

OM&A costs per installed MWh have increased compared to the same period in 2007 due to cost escalations, higher planned maintenance costs, and increased compensation costs.

Safety

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

	2006	**2007**	**2008**	**Target 09/10**
Injury Frequency Rate ("IFR")	1.96	1.76	**1.28**	Reduce >10% annually

The IFR has consistently decreased over the past three years as a direct result of our continuous efforts to improve safety.

Sustaining Capital Expenditures

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

In 2008, we spent $340 million on routine and mine capital and $125 million on planned maintenance. In 2007, we spent $293 million on routine and mine capital and $78 million on planned maintenance. The increase in both routine and mine capital and planned maintenance in 2008 compared to the same period in 2007 was due to higher unplanned outages at Alberta Thermal and Genesee 3, equipment modifications at Centralia Thermal, and higher planned maintenance activities across the fleet.

Our annual target for sustaining capital expenditures is expected to decrease for 2009 to approximately $340 to $390 million, primarily due to lower unplanned outages. We expect to return to normal sustaining capital expenditure levels of $270 to $315 million in 2010 as a result of lower productivity spending, reduced capital spending at CE Generation, LLC ("CE Gen"), and the elimination of capital spending related to Centralia Fuel Blend.

Earnings and Cash Flow From Operating Activities

We focus our base business on delivering strong earnings and cash flow growth. Comparable earnings per share[1] are targeted to increase in the low double-digit range per year with operating cash flows targeted between approximately $800 and $900 million.

	2006	2007	2008	Target 09/10
Earnings per share (comparable basis)	$ 1.16	$ 1.31	**$ 1.46**	>10% annually
Cash flow from operating activities ($ millions)	490	847	**1,038**	800-900

In 2008, earnings per share on a comparable basis increased 11 per cent to $1.46 due to favourable pricing in our core markets, higher merchant volumes due to the uprate on Unit 4 at our Sundance facility, and strong Energy Trading results across all markets, partially offset by higher unplanned outages at Alberta Thermal.

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

1 *Comparable earnings is not defined under Canadian GAAP. Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of comparable earnings, including a reconciliation to net earnings.*

In 2008, cash flow from operating activities increased 23 per cent to $1,038 million due to an increase in cash earnings and favourable changes in working capital including the timing of PPA receipts in 2008.

In 2007, cash flow from operating activities increased 73 per cent to $847 million mainly due to higher cash earnings, and receiving 12 months of contractually scheduled payments in 2007 compared to 11 in 2006.

Investment Ratios

Investment grade ratings support contracting activities and provide better access to capital markets through commodity and credit cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings. Our objective is to maintain a cash flow to interest ratio of at least four times, a cash flow to debt ratio of at least 25 per cent, and a debt to invested capital ratio of not more than 55 per cent.

Cash flow to interest increased to 7.2 times from 6.6 times in 2007 and 5.5 times in 2006. Cash flow to interest increased in 2008 compared to the same period in 2007 as a result of increased cash from operating activities and lower interest expense.

Cash flow to total debt increased to 31.1 per cent from 30.7 per cent in 2007 and 26.2 per cent in 2006. Cash flow to total debt increased in 2008 compared to the same period in 2007 due to an increase in cash flows from operating activities, which offset the increase in debt balances.

At Dec. 31, 2008, our total debt (including non-recourse debt) to invested capital was 48.1 per cent (45.6 per cent excluding non-recourse debt) compared to the Dec. 31, 2007 ratio of 46.8 per cent and Dec. 31, 2006 ratio of 44.5 per cent. Total debt to invested capital increased in 2008 compared to the same period in 2007 as a result of the issuance of senior notes in the amount of U.S.$500 million.

	2006	**2007**	**2008**	**Target 09/10**
Cash flow to interest (times)	5.5	6.6	**7.2**	Minimum 4
Cash flow to total debt (%)	26.2	30.7	**31.1**	Minimum 25
Debt to invested capital (%)	44.5	46.8	**48.1**	Maximum 55

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

Shareholder Value

Our business model is designed to deliver low-to-moderate risk-adjusted sustainable returns and maintain financial strength and flexibility, which enhances shareholder value in a capital intensive, long-cycle, commodity-based business. Our goal is to achieve consistent comparable return on capital employed ("ROCE")[2] greater than 10 per cent and total shareholder return ("TSR")[1] of 10 per cent or more per year.

The table below shows our historical performance on these measures:

	2006	**2007**	**2008**	**Target 09/10**
Comparable ROCE (%)	9.0	9.7	**9.8**	> 10% annually
TSR (%)	9.2	29.0	**(23.9)**	> 10% annually

Comparable ROCE in 2008 was consistent with the prior year. The decrease in TSR for 2008 was due to a decrease in share price during 2008 as a result of the weakening economic environment. The Standard & Poor's ("S&P")/Toronto Stock Exchange ("TSX") Composite Index decreased 35 per cent during the same period.

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These measures are not defined under Canadian GAAP. We evaluate our performance and the performance of our business segments using a variety of measures. These measures are not necessarily comparable to a similarly titled measure of another company. ROCE is a measure of the efficiency and profitability of capital investments and is calculated by taking earnings before income tax and dividing by total assets less current liabilities. Comparable ROCE measures economic value created from capital investments and is calculated *by taking comparable earnings before tax and dividing by total assets less current liabilities. Presenting this calculation using comparable earnings before tax provides management and investors with the ability to evaluate trends on the returns generated in comparison with other periods. TSR is the total amount returned to investors over a specific holding period and includes capital gains, capital losses and dividends and is calculated by taking the internal rate of return of all cash flows.*

Results of Operations

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

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

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

Highlights and Summary of Results

During 2008, we:

- generated net earnings of $235 million compared to $309 million in 2007 and $45 million in 2006,
- generated earnings on a comparable basis[1] of $290 million compared to $264 million for 2007 and $234 million for 2006,
- generated cash flow from operations of $1,038 million compared to $847 million in 2007 and $490 million in 2006, and
- generated free cash flow[2] of $121 million compared to $111 million in 2007 and $230 million in 2006.

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

Year ended Dec. 31	**2008**	**2007**	**2006**
Availability (%)	**85.8**	87.2	89.0
Production (GWh)	**48,891**	50,395	48,213
Revenue	**$ 3,110**	$ 2,775	$ 2,677
Gross margin[1]	**$ 1,617**	$ 1,544	$ 1,491
Operating income before mine closure and asset impairment charges[1]	**$ 533**	$ 541	$ 479
Mine closure charges			(192)
Asset impairment charges			(130)
Operating income[1]	**$ 533**	$ 541	$ 157
Net earnings	**$ 235**	$ 309	$ 45
Basic and diluted earnings per common share	**$ 1.18**	$ 1.53	$ 0.22
Comparable earnings per share[1]	**$ 1.46**	$ 1.31	$ 1.16

Cash flow from operating activities	**$ 1,038**	$ 847	$ 490
Free cash flow[2]	**$ 121**	$ 111	$ 230
Cash dividends declared per share	**$ 1.08**	$ 1.00	$ 1.00

As at Dec. 31	**2008**	**2007**	**2006**
Total assets	**$ 7,815**	$ 7,157	$ 7,460
Total long-term financial liabilities	**$ 3,193**	$ 2,858	$ 3,094

1
Earnings on a comparable basis, Gross margin, Operating income before mine closure and asset impairment charges, Operating income, and Comparable earnings per share are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of these items, including a reconciliation to net earnings.

2
Free cash flow is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of this item, including a reconciliation to cash flow from operating activities.

Reported Earnings

In 2008, reported earnings decreased to $235 million, compared to $309 million in 2007 and $45 million in 2006, as shown below:

Net earnings for the year ended Dec. 31, 2006	$	45
Increase in Generation gross margins		83
Mark-to-market movements Generation		(64)
Writedown of coal inventory to lower of cost and market in 2006		44
Decrease in COD margins		(10)
Decrease in operations, maintenance and administration costs		4
Decrease in depreciation expense		4
Centralia coal mine closure charges in 2006		192
Asset impairment charges in 2006		130
Gain on sale of mining equipment		16
Decrease in net interest expense		35
Increase in equity loss		(33)
Decrease in non-controlling interest		4
Increase in income tax expense		(146)
Other		5
Net earnings for the year ended Dec. 31, 2007	$	309
Increase in Generation gross margins		7
Mark-to-market movements Generation		16
Increase in COD gross margins		50
Increase in operations, maintenance, and administration costs		(60)
Increase in depreciation expense		(22)
Gain on sale of mining equipment in 2007		(11)
Decrease in net interest expense		23
Increase in equity loss		(47)
Increase in non-controlling interest		(13)
Increase in income tax expense		(3)
Other		(14)
Net earnings, 2008	**$**	**235**

Generation gross margins[1], net of mark-to-market movements, increased by $7 million for the year ended Dec. 31, 2008 due to favourable pricing, lower derates at Centralia Thermal, and higher merchant volumes as a result of the uprate on Unit 4 at our Sundance facility, partially offset by higher unplanned outages at Alberta Thermal and Genesee 3.

In 2007, generation gross margins, net of mark-to-market movements, increased $83 million as a result of lower planned outages in Western Canada combined with favourable pricing, higher production, and lower fuel costs at Centralia Thermal, partially offset by higher coal costs and higher unplanned outages in Western Canada and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, COD gross margins increased $50 million primarily due to strong results in all markets. As at Dec. 31, 2008, substantially all of these positions had been settled. In 2007, COD gross margins decreased $10 million compared to the same period in 2006 due to decreased gas and eastern region trading margins in 2007 as a result of natural gas market volatility and the strengthening of the Canadian dollar relative to the U.S. dollar.

OM&A costs for the year ended Dec. 31, 2008 increased $60 million compared to the same period in 2007 due to cost escalations, higher planned maintenance costs, and increased compensation costs. In 2007, OM&A decreased $4 million compared to the same period in 2006 primarily due to reduced operational spending across the Generation fleet, partially offset by the impact of the economic dispatch at Centralia Thermal in the second quarter of 2006, increased investment in our technological infrastructure, and higher stock compensation costs.

For the year ended Dec. 31, 2008, depreciation expense increased $22 million compared to the same period in 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal. In 2007, depreciation decreased $4 million due to the impairment recorded in 2006 on turbines held in inventory and by lower depreciation as a result of the impairment of the Centralia Gas-fired facility ("Centralia Gas") recorded in 2006.

For the year ended Dec. 31, 2008, net interest expense decreased $23 million compared to the same period in 2007 primarily due to interest received on the settlement of a tax issue and higher capitalized interest, partially offset by lower interest income from cash deposits. In 2007, net interest expense decreased $35 million mainly due to lower long-term debt levels, higher interest income on cash deposits, and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, equity loss increased $47 million compared to the same period in 2007 due to the writedown of our Mexican investment in the first quarter of 2008, partially offset by a tax expense recorded in 2007 as a result of changes in tax law in Mexico. In 2007, equity loss increased $33 million as a result of changes in Mexican tax laws, lower margins, and higher interest expense as a result of refinancing these subsidiaries, partially offset by the recognition of deferred financing fees in 2006.

1 *Gross margin is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of this item, including a reconciliation to net earnings.*

Income tax expense for the year ended Dec. 31, 2008 was comparable to the same period in 2007. In 2007, income taxes increased $146 million compared to the same period in 2006 due to higher pre-tax earnings in 2007, lower benefits from tax rate reductions relating to prior periods, and tax recoveries on the 2006 asset impairment and mine closure charges, partially offset by the recovery from resolution of uncertain tax positions in 2007. Adjusting for these items, the effective tax rate for the year ended Dec. 31, 2008 was 21 per cent compared to 23 per cent in 2007, and 20 per cent in 2006.

Significant Events

Our consolidated financial results include the following significant events:

2008

Kent Hills Wind Farm

On Dec. 31, 2008, our 96 MW Kent Hills Wind Farm, which is located 30 kilometres southwest of Moncton, New Brunswick, began commercial operations. This project was delivered on time and on budget.

Carbon Capture and Storage

On April 3, 2008, we announced an agreement with Alstom Canada to pilot chilled ammonia carbon capture technology at one of our Alberta Thermal units, contingent on acquiring adequate industry and government support.

On April 4, 2008, the Government of Canada announced a $125 million fund to support the development of CCS technologies from the oil sands and from coal-fired electricity plants, and on July 8, 2008, the Alberta government announced its commitment to provide $2 billion in funding for the development of CCS technology. These funding initiatives are key to accelerating CCS projects across Alberta and in particular, our chilled ammonia CCS pilot project with Alstom Canada. We have applied for funding support under both of these programs.

On Dec. 18, 2008, we announced the participation of TransCanada PipeLines Limited in our proposed development of Canada's first fully-integrated carbon capture and storage project. When complete, the plant will be one of the largest CCS facilities in the world and the first to have an integrated underground storage system. The project will pilot Alstom Canada's proprietary chilled ammonia carbon capture technology and will be designed to capture one megatonne of CO_2 at one of our Alberta Thermal units. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site.

Debentures

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

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

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

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

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

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

Genesee 3

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

Mexican Business

On Oct. 8, 2008, we successfully completed the sale of our Mexican business to InterGen Global Ventures B.V. ("InterGen") for gross proceeds of $334 million (U.S.$303.5 million). The sale included the plants at both facilities and all associated commercial arrangements.

The actual net loss as a result of the sale was $62 million, which is calculated below:

Contractual proceeds		$ 334
Less: closing costs		(3)
Net proceeds excluding cash on hand of $1 million		331
Book value of investment		420
Loss before deferred foreign exchange losses		89
Deferred foreign exchange losses on the net assets of the Mexican operations	$ 147	
Deferred gains on financial instruments designated as hedges of the net assets of the Mexican operations	(148)	
Income tax expense on financial instruments	9	
Deferred foreign exchange losses		8
Loss before income taxes		$ 97
Income tax recovery		35
Net loss		**$ 62**

The difference between the $65 million estimated loss on the sale of our Mexican business and the actual net loss of $62 million is due to an increase in earnings of our Mexican assets between the first quarter and the completion of the sale. The gross charge of $97 million is recorded in equity loss.

LS Power and Global Infrastructure

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

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

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

Potential Breach of Keephills Ash Lagoon

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

Expansion at Summerview

On May 27, 2008, we announced a 66 MW expansion at our Summerview wind farm located in southern Alberta near Pincher Creek. The total capital cost of the project is estimated at $123 million with commercial operations expected to commence by the first quarter of 2010.

Bond Offering

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

Normal Course Issuer Bid ("NCIB") Program

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

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

Year ended Dec. 31	**2008**	**2007**
Total shares purchased	**3,886,400**	2,371,800
Average purchase price per share	**$ 33.46**	$ 31.59
Total cost	**$ 130**	$ 75
Weighted average book value of shares cancelled	**35**	21
Reduction to retained earnings	**$ 95**	$ 54

Given the current unprecedented level of volatility in the financial markets, we have decided to suspend purchases under our NCIB program at this time in order to maintain maximum financial flexibility. We will re-evaluate financial market conditions throughout 2009 to determine the best use of cash resources going forward.

Uprate at Sundance Facility

On April 21, 2008, we announced a 53 MW efficiency uprate at Unit 5 of our Sundance facility. The total capital cost of the project is estimated at $75 million with commercial operations expected to commence by the end of 2009.

Greenhouse Gas Emissions

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

Dividend Policy and Dividend Increase

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

On March 25, 2008, the Board of Directors announced the adoption of a formal dividend policy that targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings.[1]

Blue Trail Wind Power Project

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

2007

Tax Rate Change

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

TransAlta Power, L.P.

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

Ottawa Power Purchase Agreement

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

Mexico Tax Reform

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

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1 *Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this document for a further discussion of this item, including a reconciliation to net earnings.*

NCIB Program

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

For the year ended Dec. 31, 2007, we purchased 2,371,800 shares at an average price of $31.59 per share. This purchase price was in excess of the weighted average book value of $8.92 per share, resulting in a reduction to retained earnings of $54 million.

New Brunswick Power Purchase Agreement

On Jan. 19, 2007, we announced a 25-year contract with New Brunswick Power Distribution and Customer Service Corporation ("New Brunswick Power") to provide 96 MW of wind power in New Brunswick ("Kent Hills"). We constructed, own and operate the Kent Hills facility for which commercial operations began on December 31, 2008. Total capital costs for the construction of Kent Hills were approximately $170 million. On July 17, 2007, we signed a purchase and sale agreement with Vector Wind Energy, a wholly owned subsidiary of Canadian Hydro Developers Inc., for its Fairfield Hill wind power site.

Natural Forces Technologies Inc. has an option to purchase up to 17 per cent of the Kent Hills project within 180 days from Dec. 31, 2008, the commencement of commercial operations.

Sundance Unit 4 Uprate

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

Greenhouse Gas Emissions Standards

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

Dragline Deposit

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

Keephills 3 Power Plant

On Feb. 26, 2007, we announced that we would be building the 450 MW Keephills 3 coal-fired power plant. The plant is being developed jointly by EPCOR and by us. The capital cost of the project is expected to be approximately $1.7 billion, including associated mine capital, and is anticipated to begin commercial operations in the first quarter of 2011. We own a 50 per cent interest in this unit.

2006

Centralia Coal Mine

On Nov. 27, 2006, we ceased mining activities at our Centralia coal mine as a result of increased costs and unfavourable geological conditions. Inventory extracted up to the date on which we ceased operations was mostly consumed throughout 2007. Coal requirements for the foreseeable future are expected to be sourced from coal imported from the PRB. In 2007, we reduced production at the plant by approximately 2,500 GWh. We completed the Unit 2 boiler modifications at Centralia Thermal in the second quarter of 2008 and Unit 1 boiler modifications are scheduled to begin in the spring of 2009.

We incurred an after-tax charge of $154 million ($0.76 per share) due to asset and inventory writedowns, reclamation liabilities, severance costs and other charges.

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

Writedown of coal inventory	$	44
Impact on gross margin		(44)
Mine closure charges		
Mine equipment and infrastructure writedown	$	72
ARO writedown		81
Severance costs and other		39
Total mine closure charges		192
Loss before income taxes	$	(236)
Income tax recovery		82
Net loss impact of event	$	(154)

Writedown of Coal Inventory

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

Mine Equipment and Infrastructure Writedown

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

ARO Writedown

The unamortized cost of future reclamation expenses was recognized immediately.

Severance Costs and Other

This includes salaries payable to employees, estimated benefit obligations, other transition payments as a result of the closure, amounts accrued for estimated contract termination penalties, and writedown of materials and supplies. These costs were paid in 2007 for a total of $24 million with the difference between this amount and the amount above of $39 million due to the strengthening of the Canadian dollar relative to the U.S. dollar.

Further, since Centralia Thermal was not operating at full capacity in 2007 and 2008, certain contracts were no longer backed by physical production at the plant and therefore no longer qualified for hedge accounting. Therefore, under GAAP, we recorded these contracts at fair value and as a result of differences between market prices at that time and those of the contracts, recognized mark-to-market gains on these contracts. As well, we entered into additional contracts to offset some of this exposure and recorded these contracts at fair market value. As a result, on a net basis, based on current forward price estimates at that time, we recorded mark-to-market gains of $35 million. These mark-to-market adjustments, which are not included in the table above, had no cash impact on the 2006 financial statements, although the fair market value will continue to change as market prices change until settlement occurs in future periods.

Centralia Gas Impairment

During our annual impairment review, we concluded that the full book value of our Centralia Gas facility was unlikely to be recovered from future cash flows due to changes in our outlook for the plant's profitability based on market dispatch rates and trading values. As a result, we recorded an $84 million after-tax ($0.42 per share) impairment charge to write the plant down to fair value.

Notice of Preferred Securities Redemption

On Nov. 22, 2006, we announced our intention to redeem all of our 7.75 per cent Preferred Securities, which had an aggregate principal of $175 million. We redeemed these securities on Jan. 2, 2007.

Designation of Eligible Dividends

Under the 2007 legislation enacted by the Department of Finance, Canadian residents are entitled to a higher gross-up and dividend tax credit in 2006 and subsequent years if they receive eligible dividends. The dividends paid by us during 2006, 2007 and 2008 are eligible dividends.

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

On Oct. 20, 2006, we announced that effective Jan. 1, 2007, we were amending and thereby removing the five per cent discount on the price of shares purchased through the DRASP plan and suspending the issuance of shares from treasury. Instead, shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the TSX on the investment dates. Shares issuable under the DRASP plan have not been registered under any U.S. Federal or State Securities laws and U.S. persons or residents are not eligible to participate in the DRASP plan.

Wabamun Outage

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

Sarnia Power Plant

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

Centralia Thermal Reduced Production and Economic Dispatch

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

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

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

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

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

Purchase of Wailuku River Hydroelectric L.P.

On Feb. 17, 2006, we purchased a 50 per cent interest in Wailuku River Hydroelectric L.P. through Wailuku Holding Company, LLC ("Wailuku") for cash of U.S.$1 million (CDN$1.2 million). Wailuku had debt of U.S.$19 million (CDN$22 million) at the time of acquisition. Wailuku owns a run-of-river hydro facility in Hawaii with an operating capacity of 10 MW. MidAmerican Energy Holdings Company ("MidAmerican") owns the other 50 per cent interest in Wailuku.

Change in Depreciation Rate

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

Keephills 3 Project

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

2006 Federal and Alberta Budgets

On May 24, 2006, the Alberta budget received Royal Assent. As a result, the general corporate income tax rate for Alberta was reduced from 11.5 per cent to 10 per cent effective April 1, 2006. The federal budget received Royal Assent on June 22, 2006. As a result, the general corporate federal tax rate is to be reduced from 21 per cent to 19 per cent by Jan. 1, 2010. The corporate surtax was eliminated for taxation years ended after Dec. 31, 2007 and the federal capital tax has been eliminated effective Jan. 1, 2006. The carry-forward period for non-capital losses and investment tax credits earned after 2005 was extended from 10 to 20 years. As a result of these changes, we reduced income tax expense by $55 million.

Subsequent Events

Sundance Unit 4 Derate

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

We have given notice of a High Impact Low Probability Event to the PPA Buyer and the Balancing Pool, which if successful, will protect us from the financial loss and related penalties. The available penalties that we would expect to recover in net income are anticipated to be $14 million.

Keephills Units 1 and 2 Uprates

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

Dividend Increase

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

Carbon Capture and Storage

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

Discussion of Segmented Results

GENERATION: Owns and operates hydro, wind, geothermal, natural gas- and coal-fired plants and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. At Dec. 31, 2008, Generation had 8,482 MW of gross generating capacity[1] in operation (8,073 MW net ownership interest) and 456 MW net under construction. For a full listing of all of our generating assets and the regions in which they operate, refer to page 18 of this Annual Report.

During 2008, we completed the Kent Hills wind farm in New Brunswick that added 96 MW of generating capacity. Kent Hills operates under a PPA with New Brunswick Power.

We have strategic alliances with EPCOR, ENMAX Corporation ("ENMAX"), and MidAmerican. The EPCOR alliance provided the opportunity for us to acquire a 50 per cent ownership in the 450 MW Genesee 3 project and to build the Keephills 3 project. ENMAX and our Company each own 50 per cent of the partnership in the McBride Lake wind project. MidAmerican owns the other 50 per cent interest in CE Gen and Wailuku.

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

The results of the Generation segment are as follows:

	2008		**2007**		**2006**	
Year ended Dec. 31	**Total**	**Per installed MWh[2]**	**Total**	**Per installed MWh[2]**	**Total**	**Per installed MWh[2]**
Revenues	**$ 3,005**	**$ 40.63**	$ 2,720	$ 37.03	$ 2,612	$ 35.64
Fuel and purchased power	**(1,493)**	**(20.18)**	(1,231)	(16.76)	(1,186)	(16.19)
Gross margin	**1,512**	**20.45**	1,489	20.27	1,426	19.45
Operations, maintenance and administration	**487**	**6.58**	447	6.08	458	6.25
Depreciation and amortization	**409**	**5.53**	391	5.33	397	5.42
Taxes, other than income taxes	**19**	**0.26**	20	0.27	21	0.29
Intersegment cost allocation	**30**	**0.41**	27	0.37	28	0.38
Operating expenses	**945**	**12.78**	885	12.05	904	12.34
Operating income before mine closure and asset impairment charges[3]	**567**	**7.67**	604	8.22	522	7.11
Mine closure charges					192	2.62
Asset impairment charges					130	1.77
Operating income	**$ 567**	**$ 7.67**	$ 604	$ 8.22	$ 200	$ 2.72
Installed capacity (GWh)	**73,969**		73,447		73,287	
Production (GWh)	**48,891**		50,395		48,213	
Availability (%)	**85.8**		87.2		89.0	

1

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

2

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

3

Operating income before mine closure and asset impairment charges is not defined under Canadian GAAP. Refer to the Non-GAAP Measures section on page 63 of this MD&A for a further discussion of these items, including a reconciliation to cash flow from operating activities

Generation Production and Gross Margins

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

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

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

Year ended Dec. 31, 2006	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh[1]	Fuel & purchased power per installed MWh[1]	Gross margin per installed MWh[1]
Western Canada	33,501	45,238	$ 1,291	$ 403	$ 888	$ 28.55	$ 8.90	$ 19.65
Eastern Canada	3,353	7,174	454	300	154	63.23	41.87	21.36
International	11,359	20,875	867	483	384	41.53	23.14	18.39
	48,213	73,287	$ 2,612	$ 1,186	$ 1,426	$ 35.64	$ 16.19	$ 19.45

Western Canada

Our Western Canada assets consist of five coal facilities, three natural gas-fired facilities, 13 hydro facilities, and three wind farms with a total gross generating capacity of 5,224 MW (4,937 MW net ownership interest). We are currently constructing a 450 MW (225 MW net ownership interest) merchant thermal plant at our Keephills facility under a joint venture with EPCOR, which is scheduled to enter commercial production in 2011. We are also currently constructing two wind farms, Summerview 2 and Blue Trail, in southern Alberta. Each farm will have a generating capacity of 66 MW. Blue Trail is scheduled to enter commercial production in 2009 and Summerview 2 is scheduled to enter commercial production in 2010.

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

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

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

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

For the year ended Dec. 31, 2008, production decreased 1,034 GWh compared to 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, partially offset by increased merchant production resulting from the Unit 4 uprate at our Sundance facility.

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

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

Gross margin for the year ended Dec. 31, 2008 decreased $64 million ($1.67 per installed MWh) compared to the same period in 2007 due to higher unplanned outages at Alberta Thermal and Genesee 3, and higher coal costs, partially offset by favourable pricing and higher merchant volumes due to the uprate on Unit 4 of our Sundance facility.

In 2007, gross margin decreased $35 million ($0.86 per installed MWh) compared to 2006 due to higher coal costs, higher unplanned outages at Alberta Thermal, and lower prices, partially offset by lower planned outages at Alberta Thermal and higher excess energy due to the uprate on Unit 4 of our Sundance facility.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities and one wind farm with a total gross generating capacity of 915 MW (793 MW net ownership interest). All four natural gas-fired facilities earn revenue under long-term contracts for which revenues are derived from payments for capacity and/or the production of electrical energy and steam. Kent Hills, a 96 MW wind farm located in New Brunswick, began commercial operations on Dec. 31, 2008.

For the year ended Dec. 31, 2008, production decreased 485 GWh compared to the same period in 2007, primarily due to higher planned outages and lower market heat rates at Sarnia.

In 2007, production increased 422 GWh compared to 2006 primarily as a result of favourable market conditions, higher customer demand and lower planned maintenance at Sarnia and increased production at Ottawa due to natural gas sales in the first quarter of 2006.

For the year ended Dec. 31, 2008, gross margins were comparable to the same period in 2007. In 2007, gross margins decreased $14 million ($1.80 per installed MWh) compared to 2006 as a result of lower gas sales at Ottawa.

International

Our international assets consist of natural gas, coal, hydro, and geothermal assets in various locations in the United States with a generating capacity of 2,043 MW and natural gas- and diesel-fired assets in Australia with a generating capacity of 300 MW. 385 MW of our United States assets are operated by CE Gen, a joint venture owned 50 per cent by us.

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

For the year ended Dec. 31, 2008, production increased 15 GWh compared to the same period in 2007 due to lower unplanned outages and lower derates at Centralia Thermal (in 2007 we conducted test burns of PRB coal), partially offset by higher planned outages as a result of equipment modifications made at Centralia Thermal and economic dispatching at Centralia Thermal in the second quarter.

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

For the year ended Dec. 31, 2008, gross margins increased $77 million ($3.97 per installed MWh) compared to the same period in 2007 primarily due to favourable pricing and mark-to-market movements.

In 2007, gross margins increased $112 million ($5.35 per installed MWh) due to favourable market and contractual pricing and increased production at Centralia Thermal, the writedown of inventory related to the cessation of mining activities of the Centralia coal mine in 2006, and lower coal costs at Centralia Thermal, partially offset by mark-to-market losses in 2007 versus mark-to-market gains in 2006 and the strengthening of the Canadian dollar compared to the U.S. dollar.

Operations, Maintenance, and Administration

For the year ended Dec. 31, 2008, OM&A expenses increased $40 million compared to the same period in 2007 due to cost escalations and higher planned maintenance costs.

In 2007, OM&A expense decreased by $11 million primarily due to lower operational spending and planned maintenance expenditures, partially offset by savings realized from the economic dispatch at Centralia Thermal in the second quarter of 2006.

Planned Maintenance

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

Year ended Dec. 31	2008	2007	2006
Capitalized	**$ 125**	$ 78	$ 84
Expensed	**68**	54	56
	$ 193	$ 132	$ 140
GWh lost	**3,478**	2,056	2,325

Production lost as a result of planned maintenance in the year ended Dec. 31, 2008 increased by 1,422 GWh primarily due to the Unit 2 boiler modifications at Centralia Thermal. Production lost in 2007 decreased by 269 GWh from 2006 due to reduced planned outages across the fleet.

For the year ended Dec. 31, 2008, total capitalized and expensed maintenance costs increased compared to 2007 due to the Unit 2 boiler modifications at Centralia Thermal, higher planned outages across the fleet and cost escalations. Total capital and expensed maintenance costs decreased in 2007 compared to the same period in 2006 primarily due to lower planned maintenance activity at our gas-fired facilities.

Depreciation Expense

For the year ended Dec. 31, 2008, depreciation expense increased $18 million compared to the same period in 2007 due to increased capital spending, the retirement of assets that were not fully depreciated as a result of planned maintenance activities, and the early retirement of certain components as a result of equipment modifications made at Centralia Thermal.

In 2007, depreciation expense decreased $6 million compared to 2006 due to the impairment recorded in 2006 on turbines held in inventory, lower depreciation at Centralia Gas, and the strengthening of the Canadian dollar versus the U.S. dollar, partially offset by the recording of ARO accretion at the Centralia coal mine, increased depreciation as a result of capital spending in 2006, and reduced life of certain parts at Centralia Thermal.

For active mines, accretion expense related to ARO is included in cost of sales. However, the Centralia coal mine is currently considered to be inactive and accretion expense is therefore now recorded in depreciation expense. Accretion expense of $9 million and $10 million related to the Centralia coal mine was recorded in depreciation for the years ended Dec. 31, 2008 and 2007, respectively. Accretion expense of $9 million was recorded in cost of sales for the year ended Dec. 31, 2006.

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

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

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

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

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

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

Year ended Dec. 31	**2008**	2007	2006
Gross margin	**$ 105**	$ 55	$ 65
Operations, maintenance and administration	**53**	34	37
Depreciation and amortization	**3**	1	1
Intersegment cost allocation	**(30)**	(27)	(28)
Operating expenses	**26**	8	10
Operating income	**$ 79**	$ 47	$ 55

For the year ended Dec. 31, 2008, gross margins increased $50 million compared to the same period in 2007 due to increased margins across all markets. As at Dec. 31, 2008, substantially all of these positions had been settled.

For the year ended Dec. 31, 2007, gross margins decreased $10 million compared to the same period in 2006 due to decreased natural gas and eastern region trading margins as a result of natural gas market volatility and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the year ended Dec. 31, 2008, OM&A costs increased $19 million compared to the same period in 2007, from additional trading compensation as a result of increased gross margins.

OM&A costs for 2007 decreased $3 million due to lower incentive costs as a result of decreased margins as well as lower project consulting expenses.

The inter-segment cost allocations increased slightly in 2008 due to an increase in the work performed on behalf of the Generation segment. The inter-segment cost allocations in 2007 and 2006 were comparable.

Net Interest Expense

Year ended Dec. 31	**2008**	2007	2006
Interest on long-term debt	**$ 147**	$ 145	$ 154
Interest on short-term debt	**30**	26	13
Interest income from tax settlement	**(30)**		
Interest on preferred securities			14
Interest income	**(16)**	(32)	(13)
Capitalized interest	**(21)**	(6)	
Net interest expense	**$ 110**	$ 133	$ 168

$30 million of reported interest income relates to refund interest received or due from taxation authorities for the settlement of outstanding tax issues related to prior periods.

For the year ended Dec. 31, 2008, net interest expense decreased $23 million compared to the same period in 2007 primarily due to interest income received on the settlement of the tax issue discussed above, and higher capitalized interest, partially offset by lower interest income from cash deposits.

In 2007, net interest expense decreased $35 million compared to 2006 due to lower long-term debt balances, the strengthening of the Canadian dollar relative to the U.S. dollar, the redemption of preferred securities, higher interest on cash deposits and interest capitalized related to assets under construction, partially offset by higher short-term debt balances.

Gain on Sale of Assets

As a result of the decision to cease mining activities at the Centralia coal mine in 2006, all associated mining and reclamation equipment was classified as being held for sale. All equipment was recorded at the lower of net book value or anticipated realized proceeds. These assets were included in the Generation segment. In 2007, some of this equipment had been retained for reclamation activities and some was transferred to the Highvale mine for use in production of coal inventory. The equipment retained was reclassified to property, plant, and equipment in 2008. The decision to retain equipment for use in reclamation activities at the Centralia coal mine and in operations at the Highvale mine, was arrived at as the economics of retaining these assets was greater than the potential cash proceeds from their disposal.

During 2008, mining equipment with a net book value of $2 million related to the cessation of mining activities at the Centralia coal mine was sold for proceeds of $7 million. For the year ended Dec. 31, 2007, we sold equipment with a recorded value of $31 million, received proceeds of $47 million, and recorded a pre-tax gain of $16 million.

Non-Controlling Interests

We own 50.01 per cent of TA Cogeneration, L.P. ("TA Cogen"), which owns, operates, or has an interest in five natural gas-fired and one coal-fired generating facility with a total gross generating capacity of 814 MW. A private investor owns the minority interest in TA Cogen. Our CE Gen joint venture investment includes a 75 per cent ownership of Saranac, a 320 MW natural gas-fired cogeneration facility in New York. Since we own a controlling interest in TA Cogen and Saranac, under Canadian GAAP, we consolidate the entire earnings, assets, and liabilities in relation to TA Cogen's ownership of those assets. Non-controlling interests on the income statement and balance sheet relate to the earnings and net assets attributable to TA Cogen and Saranac that are not owned by us. On the statement of cash flow, cash paid to the minority shareholders of TA Cogen and Saranac is shown as 'Distributions to subsidiaries' non-controlling interests' in the financing section.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2008 increased $13 million due to higher earnings at TA Cogen and CE Gen.

In 2007, earnings attributable to non-controlling interests decreased $4 million due to lower margins at Sheerness and Ottawa, partially offset by higher margins at Meridian.

Equity Loss

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

The table below summarizes key information from these operations.

Year ended Dec. 31	**2008**	**2007**	**2006**
Availability (%)	**97.5**	92.7	90.8
Production (GWh)	**2,646**	3,084	2,918
Equity loss	**$ (97)**	$ (50)	$ (17)
Capital expenditures	**$**	$ 1	$ 10
Operating cash flow	**$ 2**	$ (3)	$ (7)
Interest expense	**$ 13**	$ 27	$ 32

As at Dec. 31	2008	2007
Total assets	**$**	$ 451
Total liabilities	**$**	$ 369

For the year ended Dec. 31, 2008, availability increased due to lower planned and unplanned outages at Chihuahua and lower unplanned outages at Campeche. In 2007, availability increased primarily due to lower planned outages at Campeche and Chihuahua and unplanned outages at Chihuahua.

As a result of the sale of our Mexican business in 2008, total production decreased by 438 GWh compared to 2007. In 2007, production increased 166 GWh due to higher customer demand at Chihuahua and lower planned outages at Campeche and Chihuahua.

For the year ended Dec. 31, 2008, equity loss increased $47 million due to the writedown of our Mexican investment in the first quarter of 2008, partially offset by a tax expense recorded in 2007 as a result of changes in tax law in Mexico.

As described in the Significant Events section of this MD&A, on Oct. 1, 2007, the Mexican government enacted law introducing a flat tax system starting Jan. 1, 2008, and as a result, we recorded a $28 million charge to equity losses and a corresponding reduction in investments reflecting the expected impact of this change in law in 2007.

For the year ended Dec. 31, 2007, equity loss increased $33 million due to the income tax expense described above, lower margins, and increased interest costs as a result of refinancing these subsidiaries in 2006, partially offset by the recognition of deferred financing fees and the loss incurred on unwinding a cross-currency swap in 2006 related to the refinancing.

Income Taxes

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

Therefore, when a government announces a change in future income tax rates, it will affect the anticipated income tax asset or liability that will appear in our financial statements. We have seen several large reductions in future tax expense as a result of the Canadian government reducing future tax rates.

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

Year ended Dec. 31	2008	2007	2006
Earnings (loss) before income taxes per statement of earnings	**$ 258**	$ 329	$ (81)
Equity loss	**(97)**	(50)	(17)
Adjustments:			
Coal inventory writedown			44
Mine closure charges			192
Asset impairment charges			130
Turbine impairment			10
Earnings before income taxes, equity loss and other items	**$ 355**	$ 379	$ 312
Income tax expense excluding equity loss and other items	**73**	86	61
Income tax recovery on one-time adjustments	**(35)**		(132)

Income tax recovery recorded on sale of equity investment						
Income tax recovery from settlement of tax positions		**(15)**		(18)		
Change in tax rate related to prior periods				(48)		(55)
Income tax expense (recovery) per financial statements	**$**	**23**	$	20	$	(126)
Effective tax rate (%)[1]		**21**		23		20

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

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

As a result of a reduction in Canadian corporate income tax rates expected to apply to future tax liabilities, income tax expense was reduced by $48 million for the year ended Dec. 31, 2007. In 2006, this change in tax rates reduced income tax expense by $55 million.

Adjusting for the items mentioned above, income tax expense decreased for the year ended Dec. 31, 2008 compared to the same period in 2007 due to lower pre-tax income. In 2007, tax expense increased from the same period in 2006 due to an increase in pre-tax income earnings and the effect of the change in the mix of jurisdictions in which pre-tax income is earned.

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

Financial Position

The following chart outlines significant changes in the consolidated balance sheets from Dec. 31, 2007 to Dec. 31, 2008:

	Increase/ (Decrease)	**Explanation of change**
Income taxes receivable	12	Tax recovery from current year provision offset by use of tax prepayments
Inventory	21	Higher inventory balances as a result of lower production and an increase in exchange rates
Restricted cash	(242)	Return of funds
Investments	(125)	Disposal of equity investment
Risk management assets (current and long-term)	206	Price movements
Property, plant, and equipment, net	904	Capital additions and the weakening of the Canadian dollar relative to the U.S. dollar, partially offset by depreciation expense
Goodwill	17	Weakening of the Canadian dollar compared to the U.S. dollar
Assets held for sale, net	(29)	Assets previously held for sale have been reclassified to property, plant, and equipment
Other assets	(18)	Amortization and reclassification of certain costs to property, plant, and equipment
Short-term debt	(208)	Net decrease in short-term debt
Accounts payable and accrued liabilities	209	Timing of operational commitments and the weakening of the Canadian dollar compared to the U.S. dollar
Recourse long-term debt (including current portion)	504	Issuance of long-term debt of U.S.$500 million
Non-recourse long-term debt (including current portion)	24	Weakening of the Canadian dollar compared to the U.S. dollar, partially offset by scheduled debt payments
Risk management liabilities (current and long-term)	(59)	Price movements
Asset retirement obligation (including current portion)	21	Increase in estimate and the weakening of the Canadian dollar compared to the U.S. dollar, partially offset by costs settled
Deferred credits and other long-term liabilities	21	Receipt of funding from joint venture partner
Net future income tax liabilities (including current portions)	53	Tax effect on the decrease in net risk management liabilities
Non-controlling interests	(27)	Distributions in excess of earnings from TA Cogen
Shareholders' equity	211	Net earnings and movements in AOCI, partially offset by shares redeemed under the NCIB and dividends declared

Financial Instruments

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

We have two types of financial instruments: (1) those that are used in the COD and Generation segments in relation to Energy Trading activities, commodity hedging activities, and other contracting activities and (2) those used in the hedging of debt, projects, expenditures, and the net investment in self-sustaining foreign subsidiaries. The majority of the Corporation's derivatives have quoted market prices on active exchanges or over-the-counter quotes available from brokers. However, some derivatives are not traded on an active exchange or have contracts that extend beyond the time period for which market-based quotes are available, requiring us to use internal valuation techniques or models.

The majority of our financial instruments and physical commodity contracts are recorded under normal purchase/normal sale accounting or qualify for, and are recorded under, hedge accounting rules. As a result, for those contracts for which we have elected hedge accounting, no gains or losses are recorded through the statement of earnings as a result of differences between the contract price and the current forecast of future prices until the period of settlement. We record the changes in value of these contracts through the

Statement of Other Comprehensive Income ("OCI"). When these contracts are settled, the value previously recorded in OCI is reversed and we receive the contracted cash amount for those contracts.

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

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

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

Fair Value Hedges

Fair value hedges are used to offset the impact of fluctuations in the foreign currency and interest rates on various assets and liabilities. Interest rate swaps are used to hedge exposures in the fair value of long-term debt caused by variations in market interest rates by fixing interest rates. Foreign exchange contracts are used to hedge certain foreign currency denominated assets and liabilities. Based on the fair value of risk management assets and liabilities at Dec. 31, 2008, approximately 5 per cent of our financial instruments are fair value hedges.

All gains or losses related to fair value hedges are recorded on the statement of earnings, which, in turn, are completely offset by the value of the gains or losses on the fair value of the related debt instruments on the foreign currency denominated assets and liabilities. A summary of how fair value hedges are recorded in our financial statements is as follows:

Event	Statement of Earnings	OCI	Balance Sheet	Cash Flow
Enter into contract[1]				
Reporting date (marked-to-market)				
Settle contract				