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

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

For the fiscal year ended December 31, 2009 Commission file number 001-15214

TRANSALTA CORPORATION

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

Not 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:

x Annual information form **x** 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, 2009, 218,404,442 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 **x**

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 **x** No **o**

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes **x** No **o**

INCORPORATION BY REFERENCE

The documents 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
F-10	333-162418

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 Exhibit 13.3 incorporated by reference herein. For the related supplementary note entitled "Reconciliation to United States Generally Accepted Accounting Principles" containing a reconciliation of the important differences between Canadian and United States generally accepted accounting principles, see Exhibit 13.4 incorporated by reference herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see Exhibit 13.2 incorporated by reference herein.

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, 2009, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

MANAGEMENT'S ANNUAL 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, 2009 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, 2009. 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, 2009. For Ernst & Young LLP's report see page 3 of the Consolidated Annual Financial Statements for the year ended December 31, 2009 filed as Exhibit 13.3 and incorporated by reference herein, 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 Questions Nos. 1 and 15 of "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 Securities and Exchange Commission (revised September 24, 2007) (the "FAQ"). 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 as of and for the year ended December 31, 2009 in the amount of $1,576 million of the Company's total assets, $849 million of net assets, $437 million of revenues and $79 million of net earnings. 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.

On November 4, 2009 the Company completed its acquisition of all of the outstanding common shares of Canadian Hydro Developers, Inc. ("Canadian Hydro"). Management has not evaluated the internal controls of Canadian Hydro in accordance with Frequently Asked Question No. 3 of the FAQ. As a result, management's evaluation of the Company's internal control over financial reporting did not include an evaluation of the internal controls of Canadian Hydro and management's conclusion regarding the effectiveness of the Company's internal control over financial reporting does not extend to the internal controls of Canadian Hydro.

Inclusion of Canadian Hydro in the Company's financial statements as of and for the year ended December 31, 2009 contributed $1,534 million of the Company's total assets, $484 million of net assets, $29 million of revenues, and net earnings of nil.

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 Securities and Exchange Commission. 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 2009 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2009 and December 31, 2008, Ernst & Young LLP and its affiliates were paid $3,562,032 and $3,372,142 respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31	2009	2008
Audit Fees	$ 2,679,080	$ 2,594,183
Audit related fees	824,631	432,343
Tax fees	58,321	345,616

Total	**$**	3,562,032	3,372,142

No other audit firms provided audit services in 2009 or 2008.

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 to French of the Company's financial statements and other documents. Total audit fees for 2009 include payments related to 2008 in the amount of $1,212,080. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923.

Audit-Related Fees

The audit-related fees in 2009 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, public equity and debt offerings and miscellaneous accounting advice provided to the Corporation.

Tax Fees

The majority of tax fees for 2009 relate to various tax related matters in our foreign operations.

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. The policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting. In addition, this year, the ARC granted management the authority to approve *de minimus* permissible non-audit services (which are in the aggregate the lesser of 5% of the total fees paid to the external auditors or CAD$125,000) provided such services are reported to the ARC at its next scheduled meeting.

Percentage of Services Approved by the ARC

For the year ended December 31, 2009, 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 27 of Exhibit 13.2, incorporated by reference herein.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 27 of Exhibit 13.2, incorporated by reference herein, under the heading "Liquidity and Capital Resources" and page 40 of Exhibit 13.3, incorporated by reference herein, 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
Michael M. Kanovsky
Gordon S. Lackenbauer
Donna S. Kaufman (ex-officio member)

FORWARD LOOKING INFORMATION

This Form 40-F, 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 and on management's experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of 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.

In particular, this Form 40-F and the documents incorporated herein by reference contain forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development and their attendant costs; expectations relating to the timing and cost of planned uprates and upgrades at various facilities; expectations relating to the timing of the completion of the study regarding carbon capture and storage and the cost of the study; estimates of recoverable coal reserves at the Corporation's Alberta mines; TransAlta's plans to invest in new capacity; expectations for demand of electricity in both the short and long term; expectations in respect of generation production; expected environmental governmental regulatory regimes and the potential impact on the Corporation; the Corporation's trading strategies and expected contribution to gross margins; and expectations relating to the renegotiation of certain of the collective bargaining agreements to which TransAlta is a party.

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) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate the Corporation's facilities; (ix) natural disasters; (x) equipment failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) the Corporation's provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in TransAlta's Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2009 (the "**Annual MD&A**") incorporated herein by reference.

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 occur to a different extent or at a different time than the

Corporation has described or might not occur. The Corporation cannot assure you that projected results or events will be achieved.

DOCUMENTS FILED AS PART OF THIS REPORT AND EXHIBITS

The following items are specifically incorporated by reference in, and form an integral part of, this filing on Form 40-F:

13.1 TransAlta Corporation Annual Information Form for the year ended December 31, 2009.

13.2 Management's Discussion and Analysis.

13.3 Consolidated Audited Annual Financial Statements for the year ended December 31, 2009.

13.4	Reconciliation to United States Generally Accepted Accounting Principles of the 2009 Consolidated Audited Annual Financial Statements.
13.5	Management's Annual Report on Internal Control over Financial Reporting, (included on page 2 of Exhibit 13.3 filed herewith).
13.6	Independent Auditor's Report on Internal Controls under Standards of the Public Company Accounting Oversight Board (United States), (included on page 3 of Exhibit 13.3 filed herewith).
23.1	Consent of Ernst and Young LLP Chartered Accountants.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.
31.2	Certification of Chief Financial Officer pursuant to Section 302 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*.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the *Sarbanes-Oxley Act of 2002*.

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
Chief Financial Officer

Dated: February 24, 2010

EXHIBIT INDEX

13.1	TransAlta Corporation Annual Information Form for the year ended December 31, 2009.
13.2	Management's Discussion and Analysis.
13.3	Consolidated Audited Annual Financial Statements for the year ended December 31, 2009.
13.4	Reconciliation to United States Generally Accepted Accounting Principles of the 2009 Consolidated Audited Annual Financial Statements.
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13.6	Independent Auditor's Report on Internal Controls under Standards of the Public Company Accounting Oversight Board (United States), (included on page 3 of Exhibit 13.3 filed herewith).
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*.
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32.1	Certification of President and Chief Executive Officer pursuant to Section 906 of the *Sarbanes-Oxley Act of 2002*.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-*Oxley Act of 2002*.

Exhibit 13.1

TRANSALTA CORPORATION

2010 RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

FEBRUARY 24, 2010

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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, 2009. 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 and on management’s experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “anticipate”, “intend”, “plan”, “foresee”, “potential”, “enable”, “continue” or other comparable terminology. These statements are not guarantees of 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.

In particular, this Annual Information Form contains forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development and their attendant costs; expectations relating to the timing and cost of planned uprates and upgrades at various facilities; expectations relating to the timing of the completion of the FEED (as defined herein) study regarding carbon capture and storage and the cost of the study; estimates of recoverable coal reserves at the Corporation’s Whitewood and Highvale mines; TransAlta’s plans to invest in new capacity; expectations for demand for electricity in both the short and long term; expectations in respect of generation production; TransAlta’s plans to install mercury control equipment at its Alberta thermal operations and its initiative to reduce nitrogen oxide and mercury emissions from its Centralia Plant; expected governmental regulatory regimes; the Corporation’s trading strategies; and expectations relating to the renegotiation of certain of the collective bargaining agreements to which TransAlta is a party.

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) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate the Corporation's facilities; (ix) natural disasters; (x) equipment failure; (xi) trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) the Corporation's provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail 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, 2009 (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 occur to a different extent or at a different time than the Corporation has described 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, 2009 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

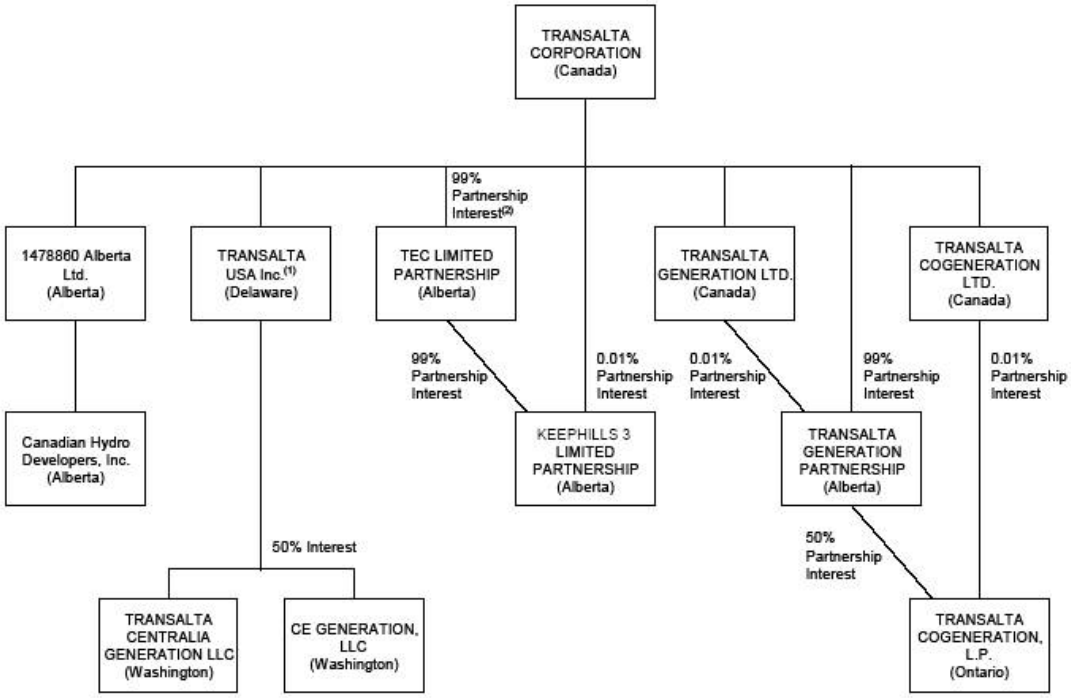
TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* (the "**CBCA**") on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving the Corporation and TransAlta Utilities Corporation ("**TransAlta Utilities**" or "**TAU**") under the CBCA. 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 again issued a Certificate of Amalgamation under the CBCA 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 - 12 th Avenue S.W., Calgary, Alberta, Canada, T2R 0G7.

Intercorporate Relationships

Effective January 1, 2009, the Corporation completed the 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 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 CBCA. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are now held directly, in the case of certain wind assets, and some of which are now held indirectly, in the case of both the former generation assets and businesses of TAU and TEC and the assets and business of Canadian Hydro Developers, Inc. ("**Canadian Hydro**"). TransAlta completed its acquisition of Canadian Hydro on November 4, 2009.

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



Notes:
(1) TransAlta USA Inc. is wholly-owned by TransAlta Holdings ULC, which is wholly-owned by TransAlta.
(2) The remaining 0.01 per cent interest in TEC Limited Partnerships is owned by TransAlta (Ft. McMurray) Ltd.

Unless the context otherwise requires, all references to the " **Corporation**" and to "**TransAlta**", "**we**", "**our**" and "**us**" 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 8,776 megawatts ("**MW**") of generating capacity[1] operating in facilities having approximately 10,578 MW of aggregate generating capacity. In addition, the Corporation has facilities under construction with a net ownership interest of 478 MW of generating capacity in facilities designed to have aggregate generating capacity of 703 MW, for total net ownership of 9,253 MW of generating capacity in facilities that have or will have aggregate capacity of 11,281 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, geothermal and biomass resources.

In Canada, the Corporation holds a net ownership interest of 6,461 MW of electrical generating capacity in thermal, gas fired, wind powered, hydroelectric and biomass facilities, including 5,244 MW in Western Canada, 1,040 MW in Ontario, 99 MW in Québec and 80 MW in New Brunswick.

[1] TransAlta measures capacity as the net maximum capacity ("NMC") that a unit can sustain over a period of time, which is consistent with the 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.

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 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, geothermal and biomass 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.

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 January 11, 2010, the Corporation announced it has been awarded a 25-year power purchase agreement to provide an additional 54 MW of wind power to New Brunswick Power Distribution and Customer Service Corporation ("**New Brunswick Power**"). The capital cost of the project is estimated to be $100 million. Construction is expected to commence in early 2010 and the facility is expected to be in service by the end of 2010.

Year Ended December 31, 2009

- On November 18, 2009, the Corporation issued $400 million principal amount of 6.4% medium term notes maturing November 18, 2019 for net proceeds to the Corporation of $397.2 million.
- On November 17, 2009, the Corporation hosted its second Alberta fixed price power auction, whereby customers were able to lock in wholesale power volumes for 2010 through 2013 at competitive market prices.
- On November 13, 2009, the Corporation issued US$500 million principal amount of 4.75% senior notes maturing January 15, 2015 for net proceeds to the Corporation of US$495.9 million.
- On November 5, 2009, the Corporation completed a public offering of 20,522,500 common shares at a price of $20.10 per common share, resulting in gross proceeds to the Corporation of approximately $412.5 million. The net proceeds from the offering were used to repay a portion of the indebtedness incurred in connection with the Corporation's acquisition of Canadian Hydro.
- On November 4, 2009, TransAlta completed the acquisition, through a wholly-owned subsidiary, of all of the issued and outstanding common shares of Canadian Hydro for aggregate cash consideration of $755.0 million. At closing of the acquisition, Canadian Hydro operated 694 MW of wind, hydro

and biomass facilities in British Columbia, Alberta, Ontario and Québec and also had 18 MW under construction.

- On October 14, 2009, the federal and provincial governments announced that the Corporation's carbon capture and storage ("**CCS**") project, Project Pioneer, had received committed funding of more than $750 million. The funding is being provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will also support the undertaking of a Front End Engineering and Design ("**FEED**") study. The FEED study is expected to cost $20 million: $10 million will come from the federal government; $5 million will come from the provincial government; and $5 million will come from the Corporation and the other industry partners. The FEED study is expected to be completed by the end of 2010. Construction of the facility, if supported as expected by the study, would be targeted for start-up in 2015. The Corporation is the managing partner of the joint government-industry partnership.
- Effective September 30, 2009, the Corporation signed a new long-term contract with the Ontario Power Authority (the " **OPA**") for the Sarnia regional natural gas cogeneration power plant. The contract is capacity based and has a term from July 1, 2009 to December 31, 2025. While the specific terms and conditions of the contract are confidential, the OPA has indicated that the agreement is in line with other similar agreements executed by the OPA.
- On May 29, 2009, the Corporation issued $200 million principal amount of 6.45% senior notes maturing May 29, 2014. The net proceeds from the offering were used for debt repayment, financing of the Corporation's long-term investment plan, and for general corporate purposes.
- On May 20, 2009, the Corporation announced that it would advance a major maintenance outage on its 353 MW Sundance 3 facility from the second quarter of 2010 into the second and third quarters of 2009.
- On May 6, 2009, the Corporation announced that it had received regulatory approval from the Toronto Stock Exchange (" **TSX**") for the renewal of its normal course issuer bid ("**NCIB**") program. Under the NCIB, the Corporation has approval to purchase for cancellation, up to 9.9 million of its common shares, representing 5 per cent of its common shares issued and outstanding as of April 30, 2009.
- On April 28, 2009, the Corporation announced plans to design, build and operate Ardenville, a 69 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the capital cost of the project is the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the remainder of the Ardenville wind project is expected to commence in the first quarter of 2011.

- 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 328 GWh and net earnings declined by approximately $10 million. On April 27, 2009, the Balancing Pool, an entity established by the Government of Alberta, rejected the Corporation's assertion that this outage should be regarded as a High Impact Low Probability Force Majeure Event. As required by the PPA legislation, the Corporation was required to pay the penalties related to the derate. The Corporation settled the issue in the third quarter and the terms of the settlement are confidential.

- On January 29, 2009, the board of directors of the Corporation (the " **Board**") 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 would 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 to be $68 million.

- Effective January 1, 2009, the Corporation completed the Reorganization whereby the assets and business affairs of TAU and TEC (with the exception of the wind business) were transferred to TransAlta Generation Partnership, an 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 a 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 CBCA. TransAlta remains the holding entity of the various businesses of the Corporation, some of which are held directly, in the case of the wind assets, and some of which are 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.

- 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 TSX for the continuation of its NCIB program. Under the NCIB program, the Corporation received 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 was approximately $113.5 million and commercial operations commenced in November 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.

- On February 20, 2008, the Corporation announced it had signed a purchase and sale agreement with Intergen Global Ventures B.V. ("**Intergen**") 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 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 of its common 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 increased by $40 million, from $130 million to $170 million. The Corporation also signed a purchase and sale agreement with Vector Wind Energy, then a wholly owned subsidiary of Canadian Hydro, 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 were approximately $150 million, with final payments for goods and services due by May 2010. The total payments made under this agreement to December 31, 2009 were $124.7 million.

- On February 26, 2007, the Corporation and EPCOR Power Development Corporation (now Capital Power Corporation or " **Capital Power**") 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 Capital Power will be equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and Capital Power responsible for the construction. Upon completion, it is expected that TransAlta will operate the facility and Capital Power and TransAlta will independently dispatch and market their share of the unit's electrical output. The project has received approval from the AEUB and from Alberta Environment.

- On January 19, 2007, the Corporation announced that it had been awarded a 25 year power purchase agreement to provide 75 MW of wind power to New Brunswick Power. Under the agreement, TransAlta constructed, owns and operates a wind power facility in New Brunswick.

- 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.

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, 2010:

Western Canada Facility	Capacity (MW) [1]	Ownership (%)	Net Capacity Ownership Interest [1]	Fuel	Revenue Source	Contract Expiry Date
Sundance	2,126	100	2,126	Coal	Alberta PPA / Merchant[2]	2017, 2020
Keephills [4]	812	100	812	Coal	Alberta PPA/Merchant[4]	2020
Sheerness	780	25	195	Coal	Alberta PPA	2020
Wabamun	279	100	279	Coal	Merchant	-
Genesee 3	450	50	225	Coal	Merchant	-
Keephills 3 [3]	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
Blue Trail	66	100	66	Wind	Merchant	-
Castle River [5]	44	100	44	Wind	LTC/Merchant	2011
Cowley North	20	100	20	Wind	Merchant	-
Cowley Ridge	21	100	21	Wind	Merchant	-
Macleod Flats	3	100	3	Wind	Merchant	-
McBride Lake	75	50	38	Wind	LTC	2024
Sinnott	7	100	7	Wind	Merchant	-
Soderglen	71	50	35	Wind	Merchant	-
Summerview 1 [6]	70	100	70	Wind	Merchant	-
Summerview 2 [3]	66	100	66	Wind	Merchant	-
Taylor Wind	3	100	3	Wind	Merchant	-
Ardenville [3]	69	100	69	Wind	Merchant	-
Akolkolex	10	100	10	Hydro	LTC	2015
Barrier	13	100	13	Hydro	Alberta PPA	2020
Bearspaw	17	100	17	Hydro	Alberta PPA	2020
Belly River	3	100	3	Hydro	Merchant	-
Big Horn	120	100	120	Hydro	Alberta PPA	2020
Bone Creek [3]	18	100	18	Hydro	LTC	2047
Brazeau	355	100	355	Hydro	Alberta PPA	2020
Cascade	36	100	36	Hydro	Alberta PPA	2020
Ghost	51	100	51	Hydro	Alberta PPA	2020
Horseshoe	14	100	14	Hydro	Alberta PPA	2020
Interlakes	5	100	5	Hydro	Alberta PPA	2020
Kananaskis	19	100	19	Hydro	Alberta PPA	2020

Pingston	45	50	23	Hydro	LTC	2023
Pocaterra	15	100	15	Hydro	Alberta PPA	2013
Rundle	50	100	50	Hydro	Alberta PPA	2020
Spray	103	100	103	Hydro	Alberta PPA	2020
St. Mary	2	100	2	Hydro	Merchant	-
Taylor Hydro	13	50	6	Hydro	Merchant	-
Three Sisters	3	100	3	Hydro	Alberta PPA	2020
Upper Mamquam	25	100	25	Hydro	LTC	2025
Waterton	3	100	3	Hydro	Merchant	-
GPEC	25	100	25	Biomass	LTC	2019-2024
Total Western Canada	**7,051**		**5,666**			

Eastern Canada

Facility	Capacity (MW) (1)	Ownership (%)	Net Capacity Ownership Interest (1)	Fuel	Revenue Source	Contract Expiry Date
Mississauga	108	50	54	Gas	LTC	2017
Ottawa	68	50	34	Gas	LTC	2012
Sarnia (7)	506	100	506	Gas	LTC	2022-2025
Windsor	68	50	34	Gas	LTC/Merchant	2016
Kent Hills	96	83	80	Wind	LTC	2033
Kent Hills Expansion (3)	54	100	54	Wind	LTC	2035
Le Nordais	99	100	99	Wind	LTC	2033
Melancthon I	68	100	68	Wind	LTC	2026
Melancthon II	132	100	132	Wind	LTC	2028
Wolfe Island	198	100	198	Wind	LTC	2029
Appleton	1	100	1	Hydro	LTC	2011
Galetta	2	100	2	Hydro	LTC	2011
Misema	3	100	3	Hydro	LTC	2027
Moose Rapids	1	100	1	Hydro	LTC	2011
Ragged Chute	7	100	7	Hydro	LTC	2011
Total Eastern Canada	**1,411**		**1,273**			

US

Facility	Capacity (MW) (1)	Ownership (%)	Net Capacity Ownership Interest (1)	Fuel	Revenue Source	Contract Expiry Date
Centralia(8)	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	Merchant	-
Yuma	50	50	25	Gas	LTC	2024
Imperial Valley Geothermal Facilities (9)	327	50	164	Geothermal	LTC	2016-2029
Skookumchuk (10)	1	100	1	Hydro	-	-
Wailuku	10	50	5	Hydro	LTC	2023
Total US	**2,464**		**2,015**			

Australia

Facility	Capacity (MW) (1)	Ownership (%)	Net Capacity Ownership Interest (1)	Fuel	Revenue Source	Contract Expiry Date
Parkeston	110	50	55	Gas	LTC	2016
Southern Cross(11)	245	100	245	Gas/Diesel	LTC	2013
Total Australia	**355**		**300**			
TOTAL	**11,281**		**9,254**			

Notes:

(1) Megawatts are rounded to the nearest whole number.
(2) Merchant capacity refers to 53 MW, 53 MW and 44 MW uprates on units 4, 5 and 6, respectively.
(3) These facilities are currently under development.
(4) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively. Merchant capacity refers to these two uprates.
(5) Includes 7 individual turbines at other locations.
(6) Comprised of 2 facilities.
(7) Sarnia's NMC has been adjusted from 575 MW due to decommissioning of equipment at the facility.
(8) 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.

(9) Comprised of 10 facilities.
(10) This facility is used to provide a reliable water supply to TransAlta's other generation facilities at Centralia.
(11) Comprised of 4 facilities.

Canada: Western Canada

Thermal facilities

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

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Wabamun[1]	AB	Wabamun Unit No. 4	279	100	1968	-
Sundance	AB	Sundance Unit No. 1	280	100	1970	2017
	AB	Sundance Unit No. 2	280	100	1973	2017
	AB	Sundance Unit No. 3	353	100	1976	2020
	AB	Sundance Unit No. 4	406	100	1977	2020
	AB	Sundance Unit No. 5	406	100	1978	2020
	AB	Sundance Unit No. 6	401	100	1980	2020
Keephills	AB	Keephills Unit No. 1[2]	406	100	1983	2020
	AB	Keephills Unit No. 2[2]	406	100	1984	2020
	AB	Keephills Unit No. 3[3]	450	50	2011	-
Sheerness	AB	Sheerness Unit No. 1	390	25	1986	2020
	AB	Sheerness Unit No. 2	390	25	1990	2020
Genesee	AB	Genesee 3	450	50	2005	-
Total			**4,897**			

Notes:
(1) Wabamun unit is expected to be removed from service upon the expiry of its license March 31, 2010.
(2) Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2011, and 2012, respectively.
(3) This facility is currently under development.

The Wabamun, Sundance and Keephills 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 Capital Power. 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 2009 was 78.0 per cent compared with 82.9 per cent in 2008 and 87.1 per cent in 2007. For the Sheerness facility, the weighted equivalent availability factor was 93.3 per cent in 2009 compared to 94.1 per cent in 2008 and 94.4 per cent in 2007. For the Genesee 3 facility, the weighted equivalent availability factor was 97.5 per cent in 2009 compared to 78.2 per cent in 2008 and 92.9 per cent in 2007.

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 Capital Power. 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 had originally proposed a 900 MW expansion at its Keephills facility. Although the Corporation received regulatory approval to proceed with the expansion, it subsequently made an application in December 2004 to amend its 900 MW permit to allow for the construction of a smaller 450 MW facility using improved technology.

The AEUB approved the amendment and on February 1, 2006, the Corporation entered into a development agreement with Capital Power, to jointly pursue the 450 MW Keephills 3 power project. On December 18, 2006, the Corporation assigned its rights in the development agreement 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 (a predecessor to Capital Power) and the parties have entered into a joint venture agreement governing the continued development of the Keephills 3 power project.

On February 26, 2007, construction of the net 450 MW Keephills 3 power project was commenced. The capital cost for the project, including mine capital, is expected to be approximately $1.9 billion and is expected to be completed at the end of the second quarter of 2011. Through K3LP, TransAlta and Capital Power are equal partners in the ownership of Keephills 3, with TransAlta responsible for managing the joint venture and Capital Power responsible for construction. Upon completion, it is expected that TransAlta will operate the facility and Capital Power 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.

Gas fired facilities

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

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Lloydminster	SK	Meridian	220	25	1999	2024
Fort McMurray	AB	Poplar Creek	356	100	2001	2024
Fort Saskatchewan	AB	Fort Saskatchewan	118	30	1999	2019
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. This 220 MW cogeneration 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 150 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 Strongwater Energy Ltd. (purchased from Air Liquide Canada Inc. in 2009). 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	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Akolkolex River System	BC	Akolkolex	10	100	1995	2015
	BC	Pingston	45	50	2003, 2004	2023
Mamquam River System	BC	Upper Mamquam	25	100	2005	2025
Thompson River System	BC	Bone Creek[2]	18	100	2011	2047
Bow River System	AB	Horseshoe	14	100	1911	2020
	AB	Kananaskis	19	100	1913, 1951	2020
	AB	Ghost	51	100	1929, 1954	2020
	AB	Cascade	36	100	1942, 1957	2020
	AB	Barrier	13	100	1947	2020
	AB	Bearspaw	17	100	1953, 1954	2020
	AB	Pocaterra	15	100	1955	2013
	AB	Interlakes	5	100	1955	2020
	AB	Spray	103	100	1951, 1960	2020
	AB	Three Sisters	3	100	1951	2020
	AB	Rundle	50	100	1951, 1960	2020
North Saskatchewan	AB	Brazeau	355	100	1965, 1967	2020
River System	AB	Bighorn	120	100	1972	2020
Oldman River System	AB	Belly River	3	100	1991	-
	AB	Waterton	3	100	1992	-
	AB	St. Mary	2	100	1992	-
	AB	Taylor Hydro	13	50	2000	-
Total			**920**			

Notes:
(1) Megawatts are rounded to the nearest whole number.
(2) Facility under construction reflects expected capacity and commissioning date.

The Corporation's Bow River and North Saskatchewan River System hydroelectric facilities are primarily peaking plants, meaning they are generally only operated during times of peak demand, and all output from these facilities is sold under one Alberta PPA.

Akolkolex River System

Akolkolex EcoPower® Centre is a run-of-river hydroelectric facility with installed capacity of 10 MW located on the Akolkolex River, south of Revelstoke, British Columbia and is owned by the Corporation. The output from the facility is sold to BC Hydro. Akolkolex has been operating since April 1995.

Pingston EcoPower® Centre is a run-of-river hydroelectric facility with installed capacity of 45 MW located on Pingston Creek, southwest of Revelstoke, British Columbia and down river of Akolkolex. The output from the facility is sold to BC Hydro. Pingston has been operating since 2003 and is 50 per cent owned, via a joint venture, with a subsidiary of Brookfield Renewable Power Inc.

Mamquam River System

Upper Mamquam EcoPower® Centre is a run-of river hydroelectric facility with installed capacity of 25 MW located on the Mamquam River, east of Squamish, British Columbia, and north of Vancouver. The output from the facility is sold to BC Hydro. Upper Mamquam has been operating since 2005.

Thompson River System

Bone Creek is a run-of-river hydroelectric facility currently under construction with expected capacity of 18 MW located on Bone Creek, north of Kamloops, near the town of Valemount, British Columbia. Bone Creek is expected to commence commercial operations in the first quarter of 2011.

Bow River System

Horeshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located in Seebe, Alberta. The plant is owned by the Corporation and has been operating since 1911.

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located in Seebe, Alberta. The plant is owned by the Corporation. The plant has been operating since 1913 and was expanded in 1951 and modified again in 1994.

Ghost is a hydroelectric facility with installed capacity of 51 MW located on the Bow River in Cochrane, Alberta. The plant is owned by the Corporation and has been operating since 1929.

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. The plant is owned by the Corporation and was purchased from the Government of Canada in 1941. The following year, TransAlta built a new dam and power plant to replace the original, the Corporation then added a second generating unit in 1957.

Barrier is a run-of-river hydroelectric facility with installed capacity of 13 MW located in Seebe, Alberta. The plant is owned by the Corporation and has been operating since 1947.

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. The plant is owned by the Corporation and has been operating since 1954.

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located in Kananaskis, Alberta. The plant is owned by the Corporation and has been operating since 1955.

Interlakes is a hydroelectric facility with installed capacity of 5 MW located in Kananaskis, Alberta. The plant is owned by the Corporation and has been operating since 1955.

Spray is a hydroelectric facility with installed capacity of 103 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. The plant is owned by the Corporation and has been operating since 1951.

Three Sisters is a hydroelectric facility with installed capacity of 3 MW located at the base of the Three Sisters Dam in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. The plant is owned by the Corporation and has been operating since 1951.

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir, which was created by the Canyon Dam to the south, and the Three Sisters dam to the north. The plant is owned by the Corporation and has been operating since 1951.

North Saskatchewan River System

Brazeau is a hydroelectric facility with installed capacity of 355 MW located in Drayton Valley, Alberta. The plant is owned by the Corporation and has been operating since 1965.

Bighorn is a hydroelectric facility with installed capacity of 120 MW located in Nordegg, Alberta. The plant is owned by the Corporation and has been operating since 1972.

Oldman River System

Belly River EcoPower® Centre is a run-of river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in southern Alberta. Due to its location along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. Belly River has been operating since March 1991. Generation from the facility is sold in the Alberta spot market.

Waterton EcoPower® Centre is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hillspring, southwest of Lethbridge, Alberta. Waterton has been operating since November 1992. Generation from the facility is sold in the Alberta spot market.

St. Mary EcoPower® Centre is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the St. Mary Dam on the Waterton Reservoir, near Magrath, in southern Alberta. St. Mary has been operating since December 1992. Generation from the facility is sold in the Alberta spot market.

Taylor EcoPower® Centre consists of separate hydroelectric and wind facilities. The hydroelectric facility (" **Taylor Hydro**") is a run-of-river facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System which is owned by the Government of Alberta. Taylor Hydro has operated since May 2000, and is jointly owned by the Corporation along with Capital Power. Generation from the facility is sold in the Alberta spot market.

Wind Generation Facilities

The Corporation owns and operates approximately 972 MW of net wind generation capacity (excluding facilities under development) primarily in 12 wind farms in western Canada, three in Ontario, one in Québec and one in New Brunswick.

As well as contracting for power, TransAlta enters into long-term and short-term contracts to sell the environmental attributes from our merchant wind and hydro facilities. These activities help to ensure earnings consistency from these assets. For 2010, TransAlta has sold approximately 70 per cent of the environmental attributes from our merchant wind facilities and 100 per cent of the environmental attributes from our merchant hydro facilities. Generally, for facilities under long term contract, the benefit of the environmental attributes generated flow through to the contract holder.

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

Location	Province	Plant	Capacity (MW) [1]	Ownership (%)	Commissioning Dates	Contract Expiry Date
Fort Macleod	AB	McBride Lake	75	50	2003	2024
Pincher Creek	AB	MacLeod Flats	3	100	2004	-
Pincher Creek	AB	Ardenville[2]	69	100	2011	-
Pincher Creek	AB	Castle River	44	100	1997-2001	2011
Pincher Creek	AB	Summerview 1	70	100	2004	-
Fort Macleod	AB	Blue Trail	66	100	2009	-
Pincher Creek	AB	Summerview 2[2]	66	100	2010	-
Pincher Creek	AB	Cowley Ridge	21	100	1993	-
Waterton	AB	Taylor Wind	3	100	2004	-
Pincher Creek	AB	Cowley North	20	100	2001	-
Pincher Creek	AB	Sinnott	7	100	2001	-
Pincher Creek	AB	Soderglen	71	50	2006	-
Total			**515**			

Notes:
(1) Megawatts are rounded to the nearest whole number.
(2) Facility under development reflects expected capacity and commissioning date.

McBride Lake is a 75 MW wind farm 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 LTC with ENMAX Energy Corp. ("**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. The Corporation also owns 100 per cent of the 0.7 MW McBride Lake East facility in the same vicinity.

Macleod Flats consists of a single Vestas V90 3 MW turbine and is located near Fort Macleod. It was commissioned in 2004 and was purchased by TransAlta in 2009.

On April 28, 2009, the Corporation announced plans to design, build and operate a 69 MW wind power project in southern Alberta (" **Ardenville**"). The capital cost of the Ardenville project is estimated at $135 million, which includes the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the remainder of the Ardenville wind project is expected to commence in the first quarter of 2011, and the output will be sold in the spot market.

Castle River is a 40 MW wind farm 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 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 Cardston County and Hillspring areas of southwestern Alberta.

Summerview is a 68 MW wind farm comprised of 38 1.8MW turbines and is located approximately 15 kilometres northeast of Pincher Creek, Alberta. It was constructed by the Corporation and commenced commercial operations in 2004. The Summerview facility, 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.

Blue Trail is a 66 MW wind farm comprised of 22 Vestas V90 3 MW turbines located in southern Alberta which commenced commercial operations in November 2009. The total capital cost for this wind power project was $115 million. The capacity from this project is 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 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. The Summerview 2 wind farm expansion is entitled to receive payments from NRCan through the eERP program.

Cowley Ridge EcoPower® Centre **("Cowley Ridge**") has total installed capacity of 21 MW and is located near the towns of Cowley and Pincher Creek, in southern Alberta. Cowley Ridge and Cowley expansion are 100 per cent owned by the Corporation, and are comprised of two parts: Cowley Ridge, which became operational in 1993, and the Cowley Expansion became operational in 1994. Generation from this facility is sold in the Alberta spot market.

Taylor EcoPower® Centre wind facility (" **Taylor Wind**") has total installed capacity of 3 MW and is located adjacent to Taylor Hydro. Taylor Wind began commercial operations in December 2004 and is owned by the Corporation. Generation from this facility is sold in the Alberta spot market.

Cowley North EcoPower® Centre (" **Cowley North**") and Sinnott EcoPower® Centre (" **Sinnott**") have a total installed capacity of 20 MW and 7 MW at Sinnot and are located adjacent to Cowley Ridge and directly east of Cowley Ridge, respectively. Cowley North and Sinnott began operations in the fall of 2001 and are 100 per cent owned by the Corporation. Generation from this facility is sold in the Alberta spot market.

Soderglen EcoPower® Centre ("**Soderglen**") is a 71 MW facility located in southern Alberta, southwest of Fort Macleod and 40 kilometres from the Corporation's wind operations near Pincher Creek. This 71 MW facility is 50 per cent owned by the Corporation and 50 per cent owned by Nexen Inc. Commercially operational in September 2006, Soderglen has a total installed capacity of 71 MW. Generation from this facility is sold in the Alberta spot market.

All of the electricity generated and sold by the Corporation's wind division, with the exception of Blue Trail, Macleod Flats, the Summerview 2 (under construction), a 2.5 MW expansion of Cowley Ridge, and Taylor Wind, is generation from 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.

Biomass Facilities

Grande Prairie EcoPower® Centre ("**GPEC**") is a biomass co-generation facility with an installed capacity of 25 MW and is located adjacent to Canadian Forest Products Ltd.'s Grande Prairie Sawmill in the city of Grande Prairie, in northern Alberta. GPEC became commercially operational in 2005. Generation from GPEC is sold to Canadian Forest Products Ltd., Alberta Infrastructure and the City of Grande Prairie.

Alberta PPAs

All of the Corporation's Alberta thermal and hydroelectric facilities, other than the Wabamun, Genesee 3, Belly River, Waterton, St. Mary and Taylor 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, other than Belly River, Waterton, St. Mary and Taylor Hydro, 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. 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 4 of the Wabamun facility until March 31, 2010, and since the extension has sold most of the electricity from the Wabamun facility on the spot market.

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 Alberta PPAs (together with legislation which applies thereto) permit the Balancing Pool, 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: Eastern Canada

Gas-fired facilities

The Corporation's Ontario gas-fired generating facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Sarnia	ON	Sarnia	506	100	2003	2022-2025
Ottawa	ON	Ottawa	68	50	1992	2012
Mississauga	ON	Mississauga	108	50	1992	2017
Windsor	ON	Windsor	68	50	1996	2016
Total			**750**			

The Sarnia plant is a combined cycle cogeneration facility which is owned by the Corporation. The Corporation acquired 135 MW of existing electric and steam generation capacity in 2002, and in March 2003 the Corporation completed construction and commissioning on a new 440 MW facility. In 2009, the Corporation decommissioned and removed a 69 MW gas turbine. The 506 MW Sarnia facility provides steam and electricity to nearby industrial facilities owned by LANXESS (formerly Bayer Inc.), Nova Chemicals (Canada) Ltd. (which in turn supplies INEOS NOVA) and Suncor Energy Products Inc. On February 15, 2006, TransAlta announced that it had signed a five year agreement with the OPA for generation from its Sarnia facility. Subsequently, the Ontario Minister of Energy and Infrastructure directed the OPA to seek contracts with TransAlta and certain over "Early Movers" on a term and under conditions more in keeping with those contracts it was offering to new facilities. In September 2009, TransAlta concluded a contract with the OPA, effective as of July 1, 2009 and terminating on December 31, 2025 under more favourable terms. This new agreement brings the combined total term contracted with the OPA to 20 years. The new contract also includes provisions to share the impact and benefit of changes in customer steam load or the loss of a steam customer.

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 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.

Hydroelectric facilities

The Corporation's Ontario hydro-electric facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) (1)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Montréal River System	ON	Ragged Chute	7	100	1991	2011
Wanapiki River System	ON	Moose Rapids	1	100	1997	2011
Mississippi River System	ON	Appleton	1	100	1994	2011
Mississippi River System	ON	Galetta	2	100	1998	2011
Misema River System	ON	Misema	3	100	2003	2027
Total			**14**			

Note:
(1) Megawatts are rounded to the nearest whole number.

Ragged Chute EcoPower® Centre ("**Ragged Chute**") is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montreal River, south of New Liskeard, in northern Ontario. Ragged Chute is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation Newenergy Canada, Inc. ("**Constellation**"). Ragged Chute has been operating since 1991.

Moose Rapids EcoPower® Centre ("**Moose Rapids**") is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. Moose Rapids is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Moose Rapids has been operating since 1997.

Appleton EcoPower® Centre ("**Appleton**") is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Mississippi River, near Appleton, Ontario. Appleton is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Appleton has been operating since 1994.

Galetta EcoPower® Centre ("**Galetta**") is a run-of-river hydroelectric facility with installed capacity of 2 MW also located on the Mississippi River, near Appleton, Ontario. Galetta is 100 per cent owned by the Corporation. Galetta was originally built in 1907 and was retrofitted in 1998. Generation from this facility is sold to Constellation.

Misema EcoPower® Centre ("**Misema**") is a run-of river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. Misema is 100 per cent owned by the Corporation. Generation from this facility is sold to Constellation. Misema has been operating since 2003.

Wind Generation Facilities

The Corporation's Ontario, Québec and New Brunswick wind generation facilities are summarized in the following table:

Location	Province	Plant	Capacity (MW) (1)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Melancthon Township	ON	Melancthon I	68	100	2006	2026
Melancthon and Amaranth Townships	ON	Melancthon II	132	100	2008	2028
Kingston	ON	Wolfe Island	198	100	2009	2029
Québec	QC	Le Nordais	99	100	1999	2033
New Brunswick	NB	Kent Hills	96	83	2008	2033
New Brunswick	NB	Kent Hills(2)	54	100	2010	2035
Total			**647**			

Notes:
(1) Megawatts are rounded to the nearest whole number.
(2) Includes the Kent Hills expansion facility under construction and expected commissioning date.

Melancthon I EcoPower® Centre ("**Melancthon I**") has total installed capacity of 68 MW and is located in Melancthon Township near Shelburne, Ontario. Melancthon I became commercially operational on March 4, 2006. Generation from this facility is sold to the Ontario Power Authority (the "**OPA**").

Melancthon II is a 132 MW wind project located adjacent to Melancthon I, in Melancthon and Amaranth Townships. Together, Melancthon I and II are known as the Melancthon EcoPower® Centre. Melancthon II achieved commercial operations on November 24, 2008. Generation from this facility is sold to the OPA.

The Wolfe Island Wind Project is located on Wolfe Island, near Kingston, Ontario. This project's key components include 86, 2.3 MW Siemens wind turbines, low voltage collector system and a high voltage transmission system, a 34.5 / 340 kV transformer station, and an operations and maintenance building. This facility is owned by the Corporation, and commenced commercial operation on June 26, 2009. Generation from this facility is sold to the OPA.

Le Nordais EcoPower® Centre ("**Le Nordais**") is located at two sites: Cap-Chat (56.25 MW installed capacity, 75 turbines); and Matane (42.75 MW installed capacity, 57 turbines). Le Nordais is on the Gaspé Peninsula of Québec. Production from this facility is sold to Hydro-Québec. Le Nordais has been commercially operational since 1999.

Kent Hills is located in Kent Hills, New Brunswick, and is a 75 MW of wind power facility with output sold under a 25 year LTC with New Brunswick Power.

On January 19, 2007, the Corporation announced that it had been awarded a 25 year LTC to deliver 75 MW of wind power to New Brunswick Power. On July 17, 2007, the Corporation announced it had amended its LTC 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. 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 exercised its option to purchase up to 17 per cent of the Kent Hills project in May 2009.

On January 11, 2010, the Corporation announced that it had been awarded another 25 year LTC to expand the existing Kent Hills project by 54 MW of wind power to New Brunswick Power with a further capital cost of an estimated $100 million. The project is scheduled to be completed by the end of 2010.

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.

United States

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

Location	State	Plant	Capacity (MW)	Ownership (%)	Commissioning Dates	Contract Expiry Date
Centralia	WA	Centralia Coal No. 1	688	100	1971	-
		Centralia Coal No. 2	688	100	1971	-
		Centralia Gas	248	100	2002	-
		Skookumchuk	1	100	1970	-
Saranac	NY	Saranac	240	37.5	1994	-
Imperial Valley	CA	Vulcan	34	50	1986	2016
		Del Ranch	38	50	1989	2018
		Elmore	38	50	1989	2018
		Leathers	38	50	1990	2019
		CE Turbo	10	50	2000	2029
		Salton Sea I	10	50	1987	2017
		Salton Sea II	20	50	1990	2020
		Salton Sea III	50	50	1989	2019
		Salton Sea IV	40	50	1996	2026
		Salton Sea V	49	50	2000	2020
Big Springs	TX	Power Resources	212	50	1988	-
Yuma	AZ	Yuma	50	50	1994	2024
Hilo	HI	Wailuku	10	50	1993	2023
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 on the Skookumchuk River near Centralia, and related assets which are used to provide water supply to TransAlta's other generation facilities at Centralia.

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.

TransAlta also owns a coal mine adjacent to the Centralia facility. 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.

During 2009, we wrote down the mining development costs incurred related to the Westfield project. These costs were carried from the shutdown of the Centralia mine as the Corporation continued to develop mining plans and longer term operation performance of Centralia Thermal. As a result of these plans being put on indefinite hold, these costs were written off.

CE Generation

TransAlta owns 50 per cent of CE Generation. 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 State, Texas and Arizona.

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

CE Generation affiliates also 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 sold its output in 2009 under a tolling agreement, but has since moved to selling its output in the spot market. The New York facility operates an energy management agreement with a third party who is responsible for marketing the output from the facility and in return, the owners receive a fixed capacity payment and 80 per cent of dispatch revenue.

Wailuku

On February 17, 2006, a subsidiary of TransAlta, together with a subsidiary of MidAmerican Energy Holdings Company 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.

Commercial Operations and Development

The Commercial Operations and 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 energy markets which are the most attractive to enter, and developing strategies and plans to effectively compete in each market where the Corporation operates;
- Negotiating and entering into contractual agreements with customers for the sale of output from the Corporation's generation assets, including electricity, steam or other energy related commodities;
- Negotiating and managing fuel supply arrangements with third parties for the Corporation's generation assets;

- 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 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 and 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 and 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 the western U.S. The Corporation also owns and operates generating assets in British Columbia, Ontario, Québec, New Brunswick and Australia.

The Corporation expects electricity demand to grow as the current recession ends. In the long term, most markets are expected to show growing demand for electricity, however, an increasing emphasis on efficiency may reduce future growth rates below historical levels. 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 most forms of renewable generation also involve intermittent or uncertain levels and timing of production, higher levels of renewable generation may be accompanied by greater capacity requirements. The Corporation believes that continued and growing demand for electricity, renewable portfolio standards, and the potential of increasing amounts of renewable generation to require additional capacity may provide an opportunity to increase its generation capacity.

Alberta is Canada's fourth largest province by population with approximately 3.7 million residents representing approximately 11 per cent of Canada's total population. Alberta consumed approximately 70,000 GWh of electricity in 2009. As at December 31, 2009, the aggregate installed capacity of generating facilities in Alberta was approximately 12,800 MW.

Electrical utilities in the U.S. and Canadian 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 370,000 GWh of electricity was consumed in the NWPP in 2009. The WECC also reported an estimated aggregate electrical generating capacity of approximately 86,000 MW in the NWPP for the year ending 2009.

British Columbia is Canada's third largest province by population with approximately 4.5 million residents, representing approximately 13 per cent of Canada's total population. In 2007, British Columbia adopted "The BC Energy Plan" which sets to "develop realistic and achievable goals for conservation, energy efficiency and clean energy". Under the

BC Energy Plan, British Columbia will be self-sufficient by 2016 with "insurance" power to supply increased demand levels.

Ontario is Canada's largest province with approximately 13.1 million residents representing approximately 39 per cent of Canada's total population. Ontario consumed approximately 139,000 GWh of electricity in 2009. Ontario Power Generation Inc., the successor to the generation business of Ontario's former integrated electric utility, controls two thirds of Ontario's approximately 35,465 MW of installed capacity, the balance of which is owned by municipal electric utilities and private independent power producers or industrial consumers.

Québec is Canada's second largest province by population with approximately 7.8 million residents, representing approximately 23 per cent of Canada's total population. The government in Québec has established the province's Energy Strategy which includes up to 4,500 MW of additional hydroelectric capacity and 4,000 MW of wind capacity installed by 2015.

In New Brunswick, wholesale and industrial consumers are allowed to purchase power from either New Brunswick Power or a competing supplier. This competitive market does not extend to retail customers, businesses or small industries. In 2007, New Brunswick announced the Charter for Change requiring 10 per cent of electricity purchases to be from renewable sources commencing in 2016.

Australia is heavily dependent on coal for electricity, with over 80 per cent of the power produced 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 283,000 GWh for 2009 with a growth rate of approximately 2.8 per cent per annum from 2010 to 2015. 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 300 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 77 per cent of the Corporation's generating capacity is contracted through PPAs, LTCs or other wholesale market transactions for the next five years. The net revenue received under these contractual arrangements helps to minimize short term revenue fluctuations due to the variable price of electricity.

Fuel diversity - - The Corporation has a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, geothermal, wind and biomass. 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 and Development expertise - The Corporation believes that its Commercial Operations and 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:

	Sustaining Capital[1]	Growth Capital[2]	Total Expenditures
2009	$380 million	$1,290 million	$1,670 million
2008	$465 million	$541 million	$1,006 million
2007	$371 million	$228 million	$599 million
2006	$207 million	$17 million	$224 million
2005	$287 million	$39 million	$326 million

Notes:
(1) Sustaining capital includes routine and productivity expenditures, mining equipment and land purchases, equipment modifications at Centralia, and planned maintenance.
(2) Growth capital consists primarily of expenditures for Keephills 3, the acquisition of Canadian Hydro, uprates and wind projects.

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 and are part of our long term strategy.

To meet regulatory requirements and improve environmental performance, TransAlta made environmental operating and capital expenditures in fiscal year 2009 of approximately $45 million. Long term 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 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 renewable energy business, with minimal emissions footprint; and
- Initiation of the Project Pioneer carbon capture and storage demonstration project in Alberta.

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

In December 2009, the Copenhagen Accord on climate change was negotiated and announced by participating countries. The Accord is not binding and does not stipulate a global target for greenhouse gas ("**GHG**") reductions. Countries are responsible for determining their own targets and policies to manage emissions. The Government of Canada had targeted a 20 per cent GHG reduction by 2020. However, the Government of Canada has not yet implemented a framework or regulations to that effect and has consistently stated that it intends to coordinate its climate change policies with those of the U.S. to facilitate a continental cap and trade system. TransAlta anticipates that the details and schedule of the Canadian program will depend on the development and direction of the U.S. approach.

Separately, the Government of Canada announced its intent to develop new Canadian air pollutant requirements for sulphur dioxide, nitrogen oxide ("**NOx**") and mercury. No regulations have yet been developed. Work continues through a stakeholder consultation process involving industry, provincial and federal governments, and environmental organizations. There is currently no defined date for the finalization and implementation of any recommendations.

On December 1, 2009, the Government of Ontario released its mandatory GHG reporting regulation, requiring industrial facilities over 25,000

tonnes of carbon dioxide ("**CO2**") emissions per year to report annually. The first reporting is required by June 2011 for 2010 emissions. This regulation is intended to lay the groundwork for an Ontario-based GHG regulatory framework to be implemented in 2010.

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

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

On October 14, 2009, the Alberta and Canadian governments each announced that Project Pioneer, TransAlta's CCS project, had received committed funding of more than $750 million. This funding is provided as part of the Government of Canada's $1 billion Clean Energy Fund and the Government of Alberta's $2 billion CCS initiative. The funding will support the undertaking of FEED study that is expected to be completed in 2010. Once built, 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 CO2 per year at our Keephills 3 facility. The CO2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site.

In addition, TransAlta looks to advance other clean energy technologies through organizations such as the Canadian Clean Coal Power Coalition which examines emerging clean combustion technologies such as gasification. TransAlta is also part of a group of companies participating in the Integrated CO2 Network to develop carbon capture and storage systems and infrastructure for Canada.

United States

In the United States, the Senate is currently considering GHG legislation following passage in the U.S. House of Representatives of the American Clean Energy and Security Act in June 2009. The legislation is based on a cap and trade system which is designed to achieve a 17 per cent reduction in GHG emissions by 2020. There is significant uncertainty regarding the form and schedule of legislation from the Senate.

Meanwhile, the U.S. Environmental Protection Agency (the "**EPA**") is pursuing a separate path to regulate GHG's under the Clean Air Act. In November 2009, the EPA upheld its endangerment finding which determines that CO2 is a pollutant and, therefore, able to be regulated by the EPA under the Clean Air Act. The implications of a legislative option versus the EPA regulatory approach is uncertain. In September 2009, the EPA adopted a mandatory GHG reporting rule for all facilities emitting more than 25,000 tons per year of CO2 equivalents. This rule became effective on December 29, 2009, and will require reporting to commence for such facilities in the U.S., including our Centralia facilities, during 2010.

In May 2009, in the state of Washington, the governor signed an executive order outlining the state government's plan for addressing climate change related emissions. The executive order included a directive to the State Department of Ecology to work with TransAlta to apply the Washington's GHG performance standard for power generation to the Centralia facilities no later than 2025. The standard will require emissions of approximately 0.5 tonnes/MWh, or about half of what is currently emitted at Centralia. Exploratory discussions are underway with the State Department of Ecology about how this might be achieved. At this time, it is not clear how Washington's target and timeframe will align with federal GHG legislation when it comes into effect.

Further, in the state of Washington, since September there has been a public process to review a draft agreement between TransAlta and Washington regarding TransAlta's voluntary initiative to reduce NOx and mercury emissions from the Centralia facilities. Specifically, TransAlta has proposed to:

- control NOx emissions to a maximum of 0.24 lbs/million BTU's fuel input, and
- reduce mercury emissions by 50 per cent from current levels.

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

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.

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.

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 strength of the economy, the available transmission capacity, 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;
- global demand for energy products;
- the cost of carbon and other environmental concerns;
- weather-related disruptions affecting ability to deliver fuels or near-term demand for fuels;
- 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 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 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 and 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, and mandatory GHG reporting requirements will be effective for 2010 in both Ontario and the United States. In both Canada and the U.S., GHG legislation or alternative forms of regulation are still under development, and it is too early to determine their impacts. 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 its customers under its 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 aspects 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 PPAs.

Under the government mandated Alberta PPAs pursuant to which the Corporation operates most of its thermal and hydroelectric 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 thermal 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.

Variations in weather can affect demand for electricity and the Corporation's ability to generate electricity.

By the nature of the Corporation's business, the Corporation's earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect the Corporation's hydroelectric assets.

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

Hydroelectric, natural gas, biomass 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 jurisdictions where the Corporation operates. Any such change in regulations could have a material adverse effect on the Corporation.

Dam failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities.

The occurrence of dam failures at any of our hydroelectric facilities could result in a loss of generating capacity, and repairing such failures could require us to incur significant expenditures of capital and other resources. If such failures occur, we could be exposed to significant liability for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Upgrading all dams to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam failures could have a material adverse effect on the Corporation. We attempt to manage this risk by following preventative maintenance procedures and obtaining insurance coverage, however, in the event of a sufficiently large dam failure, insurance coverage may not be adequate and we may suffer a material adverse effect.

Variation in wind levels may negatively impact the amount of electricity generated at the Corporation's wind facilities.

Wind is naturally variable. Therefore, the level of electricity production from our wind facilities will also be variable. In addition, the strength and consistency of the wind resource at our wind facilities may vary from what we anticipate due to a number of factors including: the extent to which our site-specific historic wind data and wind forecasts accurately reflects actual long-term wind speeds, strength and consistency; the potential impact of climatic factors; the accuracy of our assumptions relating to, among other things, weather, icing and soiling of wind turbines, site access, wake and line losses and wind shear; the potential impact of topographical variations; and the potential for electricity losses to occur before delivery.

A reduced amount of wind at the location of one or more of our wind facilities over an extended period may reduce the production from such facilities, as well as any environmental attributes that accrue to the Corporation and reduce our revenues and profitability.

Disruption in fuel supply from forest products industry could negatively impact our biomass facility.

GPEC has its full electrical capacity committed to long term contracts, which requires consistent wood waste deliveries for fuel. These fuel deliveries are in part supplied directly from the on-site customer, with the balance delivered by truck from other customer owned facilities. Loss of the on-site supply of wood waste may result in increased fuel expense in order to continue to meet all electrical supply obligations.

The Corporation could be adversely affected by natural disasters or other catastrophic events.

The Corporation's generation facilities and its operations are exposed to potential damage and partial or complete loss, resulting from environmental disasters (e.g. floods, high winds, fires, and earthquakes), equipment failures and other events beyond our control. The occurrence of a significant event which disrupts the ability of the generation facilities to produce or sell power for an extended period, including events which preclude existing customers from purchasing electricity, could have a material adverse effect on the Corporation. The Corporation's generation facilities could be exposed to effects of severe weather conditions, natural disasters and potentially catastrophic events such as a major accident or incident at the Corporation's sites or at a generating facility owned by a third party to which the Corporation's transmission assets are connected. In certain cases, there is the potential that some events may not excuse the Corporation from performing its obligations pursuant to agreements with third parties. The fact that several of the Corporation's generation facilities are located in remote areas may make access for repair of damage difficult.

Equipment failure may have a material adverse effect on the Corporation.

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could materially adversely affect the Corporation. Although the Corporation's generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. In addition, there can be no assurance that any applicable insurance coverage would be adequate to protect the Corporation from material adverse effects.

Trading risks may have a material adverse effect 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 medium 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 conducted by the Corporation's independent Risk Management Group to limit its exposure to risks arising from its trading activities, including value at risk, stop loss restrictions, stress testing, 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.

The Corporation operates a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the United States and Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity and international conglomerates. Some competitors have significantly greater financial and other resources than we do. Competitive harm 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, there can be no assurance that these risk management efforts will be effective and 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, which could have a material adverse effect on the Corporation.

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 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 or 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 material compliance with all applicable tax interpretations, regulations, and legislation, the Corporation cannot guarantee that it will not have disagreements with taxation authorities with respect to the Corporation's tax filings that could have a material adverse effect on the Corporation.

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 and as a party in commercial disputes which are

resolved by arbitration. 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 satisfactory 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. The Corporation expects to re-negotiate six collective bargaining agreements, involving 404 of its employees, in 2010 and an additional three collective bargaining agreements, involving 540 of its employees, in 2011. 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.

Risks relating to TransAlta's development projects and acquisitions may materially adversely affect the Corporation

TransAlta continues to focus on expanding its business through development projects and acquisitions. The development and construction of the Corporation's projects are subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third party opposition, cost escalations, construction delays, shortages of raw materials or skilled labour and capital constraints. Such risks may have a material adverse impact on TransAlta's business, financial condition, results of operations and cash flows.

Expansion of TransAlta's business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development projects could have a material adverse impact on TransAlta's business, financial condition, results of operations and cash flows. Further, TransAlta cannot make assurances that it will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

With respect to acquisitions, TransAlta cannot make assurances that it will identify suitable transactions or that it will have access to sufficient resources, through its credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition the Corporation

proposes or completes would be subject to normal commercial risks that the transaction may not be completed on the terms negotiated, on time, or at all. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition, including the acquisition of Canadian Hydro. The existence of such undisclosed liabilities may have a material adverse impact on the Corporation's business, financial condition, results of operations and cash flows.

EMPLOYEES

As of December 31, 2009, the Corporation had 2,228 full and part time employees, of which 1,295 were employed in TransAlta's generation business and 59 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 2009, the Corporation renewed five of the agreements; an additional six 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 February 22, 2010, there were 218,597,610 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 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 at the rate established by the Board 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 Board 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 then consists of less than 16 directors, or three directors if the Board 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, 2009, the Corporation's corporate credit rating from S&P was BBB (stable), its senior unsecured debt rating from Moody's was Baa2 (stable), and its issuer rating from DBRS was BBB (stable).

Senior Unsecured Long Term Debt

As of December 31, 2009, 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 dividends, the Board 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 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

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
2009	First Quarter	$0.29
	Second Quarter	$0.29
	Third Quarter	$0.29
	Fourth Quarter	$0.29

On January 29, 2010, the Corporation's Board of Directors declared a cash dividend of $0.29 per common share, payable on April 1, 2010 to shareholders of record on March 1, 2010.

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:

Month	Price ($)		Volume
	High	Low	
2009			
January	26.60	21.13	10,881,392
February	22.96	18.50	16,191,905
March	21.05	17.96	23,251,069
April	21.29	18.14	18,614,529
May	21.57	19.81	17,675,250
June	23.93	19.80	23,782,366
July	22.40	20.56	13,891,386
August	22.91	20.86	17,313,964
September	22.22	20.61	13,392,244
October	22.05	20.10	12,836,564
November	22.23	20.04	19,249,898
December	23.65	21.51	15,714,132
2010			
January	23.98	22.06	12,926,828
February 1 to 22	24.00	21.62	7,670,115

PRIOR SALES

In the 12 months prior to the date hereof, the following securities of the Corporation have been issued:

Common Shares

The following table summarizes the issuances of Common Shares within the twelve month period prior to the date of this short form prospectus.

Date(s) of Issuance	Number of Common Shares or Securities	Issue Price per Security	Description of Transaction
November 5, 2009(1)	20,522,000 Common Shares	$20.10	Public Offering

Note:
(1) Common Shares were issued pursuant to the Corporation's public offering of Common Shares pursuant to a prospectus supplement dated October 29, 2009. See "General Development of the Business —Year Ended December 31, 2009".

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of the directors and officers of TransAlta as at February 21, 2010, 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(1)	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 Chair of the Board 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 in business administration from the University of Western Ontario (London, ON) and is a Chartered Accountant.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
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 Sciences Corporation and is a member of its Audit Committee and Governance Committee. At TransAlta, Mr. Baum is a member of the Audit and Risk Committee and 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[2] Maryland, U.S.A.	1999	***Corporate Director.*** Mr. Bright was Chairman, President and CEO of MidAmerican Energy Company ("**MidAmerican**") from 1997 to 1999 (electric and gas utility). He was also Chairman, President, 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 merger related 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 a member of the Human Resources Committee of the Board.

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

Name, Province (State) and Country of Residence[1]	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 held 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 and AMEC plc. He is a past director of Enerflex Systems Income Fund. At TransAlta, Mr. Faithfull is Chair of the Human Resources Committee of the Board. Mr. Faithfull holds a master of arts 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*** *(law firm).* 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 Just Energy Income Fund. At TransAlta, Mr. Giffin is Chair of the Governance and Environment Committee of the Board.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
		Mr. Giffin holds a bachelor of arts from Duke University (Durham, NC) and a juris doctorate from Emory University School of Law (Atlanta, GA).

C. Kent Jespersen 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., CCR Technologies Ltd. and Orion Oil & Gas Ltd. and a director of Matrikon Inc., Axia NetMedia Corporation and CanElson Drilling Inc. At TransAlta, Mr. Jespersen is a member of the Governance and Environment 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 $3.4 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 of the Board.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
		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 (law firm). 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. She has also served on the boards of Southam Inc., Provigo Inc., Bell Canada International Inc., Bell Globemedia Inc., the Public Sector Pension Investment Board, the Hudson's Bay Company and UPM-Kymmene Corporation. She also currently serves on the boards of BCE Inc. and Bell Canada. She is also a director of The Historica-Dominion Institute, a private-sector education initiative to promote knowledge of Canadian history and heritage, 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 and in 2009 she was appointed a member of the Prime Minister's Advisory Committee on the Public Service of Canada. 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 from McGill University (Montréal, QC) and a master of laws from the Université de Montréal (Montréal, QC).
Gordon S. Lackenbauer[3] 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 Chair of its Audit Committee and a member of both the Corporate Governance and Reserves Committees. He is also a director of CTV Globemedia Inc.

Name, Province (State) and Country of Residence[1]	Year first became Director	Principal Occupation
		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.
Dr. Martha C. Piper British Columbia, Canada	2006	***Corporate Director.*** Dr. Piper was President and Vice-Chancellor of the University of British Columbia ("**UBC**") 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 served as Chair of 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 18 international universities. Dr. Piper is an Officer of the Order of Canada and a recipient of the Order of British Columbia.

Name, Province (State) and Country of Residence[1]	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 Intact Financial Corporation and director of the Calgary Stampede Foundation Campaign. He is an immediate past Director of the Canadian Imperial Bank of Commerce, past Chair of the Calgary Stampede Foundation, and past Chair of the Alberta Secretariat for Action on Homelessness. Mr. Snyder is the past Chair of the Calgary Committee to End Homelessness, the Canada-Alberta ecoEnergy Carbon Capture & Storage Task Force, the Conference Board of Canada, the Calgary Zoological Society, the Canadian Electrical Association, the United Way Campaign of Calgary and Area, and the Calgary Zoo's "Destination Africa" capital 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 and in 2009 the Chamber of Commerce Sherrold Moore Award of Excellence.

Notes:

(1) The following nominee directors are Canadian residents: William D. Anderson, C. Kent Jespersen, Michael M. Kanovsky, Donna Soble Kaufman, Gordon S. Lackenbauer, Martha C. Piper and Stephen G. Snyder.

(2) 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.

(3) 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
Dawn L. Farrell	Chief Operating Officer	Alberta, Canada
Brian Burden	Chief Financial Officer	Alberta, Canada
Kenneth S. Stickland	Chief Legal Officer	Alberta, Canada
Michael Williams	Chief Administration Officer	Alberta, Canada
William D. A. Bridge	Chief Technology Officer	Alberta, Canada
W. Frank Hawkins	Vice-President and Treasurer	Alberta, Canada
Hume D. Kyle	Vice-President, Finance and Controller	Alberta, Canada
Maryse C. St.-Laurent	Vice-President and 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 April 2009, Dawn Farrell was Executive Vice-President, Commercial Operations and Development of the Corporation. Prior to July 2007, she was Executive Vice-President Engineering, Aboriginal Relations and Generation at BC Hydro and prior to June 2006 she was Executive Vice-President Generation.

- Prior to April 2009, Brian Burden was Executive Vice-President and Chief Financial Officer of the Corporation. Prior to December 2005, he 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 April 2009, Kenneth Stickland was Executive Vice-President, Legal, SD and EH&S of the Corporation. Prior to April, 2007, he was Executive Vice-President, Legal.

- Prior to April 2009, Michael Williams was Executive Vice-President, Human Resources, IT and Communications of the Corporation. Prior to July 2007, he was Executive Vice-President, HR & Communications.

- Prior to April 2009, William Bridge was Executive Vice-President, Generation Technology and PMM of the Corporation. Prior to July 2007, he 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 and Development, Eastern Canada.

- Prior to April 2009, Frank Hawkins was Vice-President and Treasurer of the Corporation. Prior to June 2007, he was Assistant Treasurer.

- Prior to February 2009, Hume Kyle was Vice-President, Finance and Chief Financial Officer of Fort Chicago Energy Management Ltd.

- Prior to April 2009, Maryse St.-Laurent was Corporate Secretary of the Corporation. Prior to June 2005, she 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 February 23, 2010, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over an aggregate of 722,564 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 2010 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, 2009, there has been no 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 10 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:

(i) 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

(ii) 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 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 member of the Board 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 26 and 28 of the

Corporation's audited consolidated financial statements for the year ended December 31, 2009 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 Montréal. 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 – 2 nd 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 Vice-President and 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, 2009 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 five independent members, William D. Anderson (Chair), Stephen L. Baum, 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 CEO of a public company and as CFO 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 chair and 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.
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.
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.

Name of ARC Member	Relevant Education and Experience
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, 2009 are:

Governance and Environment Committee	Human Resources Committee
Chair: Ambassador Gordon D. Giffin	**Chair: Timothy W. Faithfull**
C. Kent Jespersen	Stephen L. Baum
Gordon S. Lackenbauer	Stanley J. Bright
Dr. Martha C. Piper	Dr. Martha C. Piper
Donna Soble Kaufman (ex officio)	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, 2009 and December 31, 2008, Ernst & Young LLP and its affiliates were paid $3,562,032 and $3,372,142, respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31	2009	2008
Audit Fees	$ 2,679,080	$ 2,594,183
Audit related fees	824,631	432,343
Tax fees	58,321	345,616
Total	**$ 3,562,032**	**$ 3,372,142**

No other audit firms provided audit services in 2009 or 2008.

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 2009 include payments related to 2008 in the amount of $1,212,080. Total audit fees for 2008 include payments related to 2007 in the amount of $1,403,923.

Audit Related Fees

The audit-related fees in 2009 were primarily for work performed by Ernst & Young LLP in relation to the implementation of International Financial Reporting Standards, public equity and debt offerings and miscellaneous accounting advice provided to the Corporation.

Tax Fees

The majority of tax fees for 2009 relate to various tax related matters in our foreign operations.

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 (the "**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. The Policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting. In addition, this year, the ARC granted management the authority to approve *de minimus* permissible non-audit services (which are in the aggregate the lesser of 5 per cent of the total fees paid to the external auditors or $125,000) provided such services are reported to the ARC at its next scheduled meeting.

APPENDIX "A" – 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 responsibilities to shareholders, the investment community and others, relating to the integrity of the Corporation's financial statements, the financial reporting process, the systems of internal financial controls, the risk identification assessment conducted by management and the programs established by management in response to such assessment, the internal audit function and the external auditors' qualifications, independence and performance. 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 the 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) subject to the delegation granted to the Chair of the Committee, 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; the "Management's Discussion and Analysis" and any required reconciliation;

(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 are not a regular 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", US GAAP Note, the related earnings release, and approve the release of all to the public;

(e) review and discuss with management and the 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 prior to dissemination to the public;

(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 and 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 Corporation's financial statements;

(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 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, approving the broad

objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon 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. The Committee shall also 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 and their use of Corporate assets;

(u) review annually the Corporation's annual sponsorship, donations and political contributions;

(v) 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;

(w) 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;

(x) 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 Corporation's internal controls was reported to the Committee;

(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 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, termination or transfer of the Vice-President, Internal Audit.

2. Risk Management

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 to take 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 the Corporation's 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 potential 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 the Corporation is exposed to;

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

(iv) the overall effectiveness of the enterprise risk management process.

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 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.

APPENDIX "B" – GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

"**AEUB**" means the then 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;

"**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.

TransAlta

TransAlta Management's Discussion and Analysis

December 31, 2009

PLANT SUMMARY

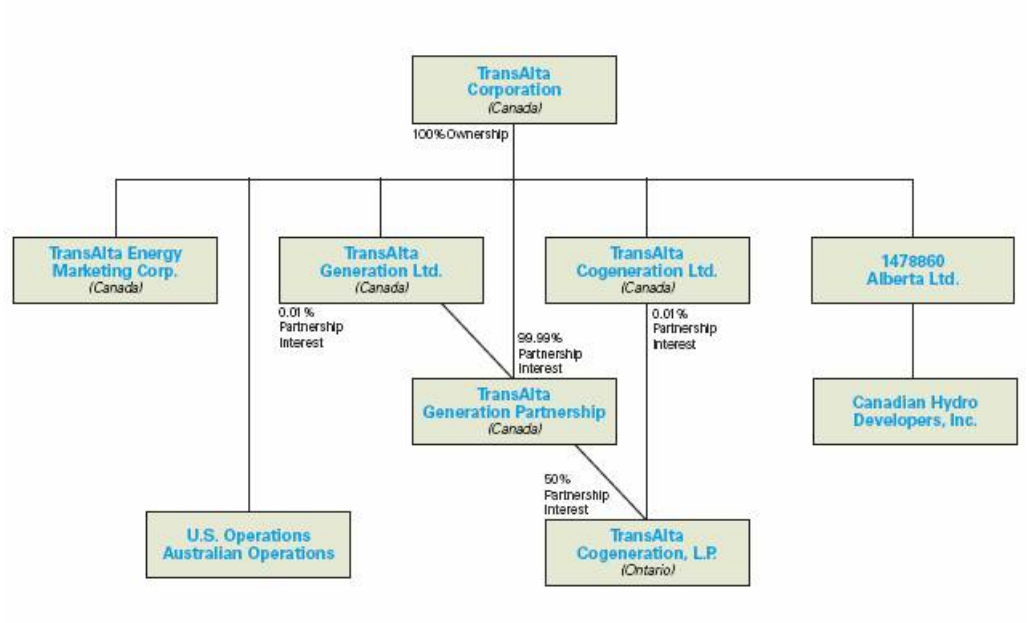
As of January 31, 2010	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Fuel	Revenue source	Contract expiry date
Western Canada 44 Facilities	Sundance, AB	2,126	100	2,126	Coal	Alberta PPA/Merchant[2]	2017, 2020
	Keephills, AB[3]	812	100	812	Coal	Alberta PPA/Merchant	2020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

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

to be commercial in 2011 and 2012, respectively
4 *These facilities are currently under development*
to decommissioning of equipment at the facility
11 *Comprised of 4 facilities*

MANAGEMENT'S DISCUSSION AND ANALYSIS

3 Business Environment 5 Strategy 5 Capability to Deliver Results 6 Performance Metrics 9 Results of Operations 10 Reported Earnings 11 Significant Events 16 Subsequent Events 16 Discussion of Segmented Results 21 Financial Position 22 Financial Instruments 25 Statements of Cash Flows 26 Liquidity and Capital Resources 27 Climate Change and the Environment 29 2010 Outlook 32 Risk Management 39 Critical Accounting Policies and Estimates 43 Future Accounting Changes 44 Non-GAAP Measures 47 Forward Looking Statements



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

BUSINESS ENVIRONMENT

Overview of the Business

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

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

Demand

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

Supply

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

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

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

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

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

Transmission

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

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

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

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

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

Environmental Legislation and Technologies

Environmental issues and related legislation have, and will continue to have, an impact upon our business. Since 2007, we have incurred costs as a result of GHG legislation in Alberta. Legislation in other jurisdictions and at different levels of government is in various stages

of maturity and sophistication. Our exposure to increased costs as a result of environmental legislation in Alberta is minimized through change-in-law provisions in our Power Purchase Arrangements ("PPAs").

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

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

Economic Environment

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

Electricity Prices

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



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

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

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

results.

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

Spark Spreads

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

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

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



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

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

STRATEGY

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

Financial Strategy

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

Contracting Cash Flows

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

Operational Strategy

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

Growth Strategy

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

CAPABILITY TO DELIVER RESULTS

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

Operational Excellence

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

Execution of our Strategy in 2009

Improve base operations	n	Improved our cash flows through PPAs and other long-term contracts, which includes a new contract with the Ontario Power Authority for our Sarnia power plant that extends to 2025
	n	Completed Unit 1 boiler modifications at Centralia Thermal
	n	Implemented productivity and cost reductions
	n	Revised our Alberta Thermal plants major maintenance schedule on a unit-by-unit basis to improve stability and predictability

Reposition coal	n	Partnered with Alstom Canada, Capital Power Corporation, and the federal and provincial governments to fund Project Pioneer, our CCS pilot project
Green our portfolio	n	Completed the 66 MW Blue Trail wind farm and have an additional 189 MW of wind energy under construction that is scheduled to be operational between Q1 2010 and Q1 2011
	n	Accelerated the growth of our renewables portfolio with the acquisition of Canadian Hydro
	n	Approved the expansion of Kent Hills and the construction of Bone Creek
	n	Continued our work on the construction of our Ardenville and Summerview 2 wind farms
	n	Continued active involvement in environmental policy discussions with various levels of government in Canada and the U.S.

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

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

Financial Strength

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

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

Disciplined Capital Allocation

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

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

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

People

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

PERFORMANCE METRICS

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

Availability

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

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

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

Production

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

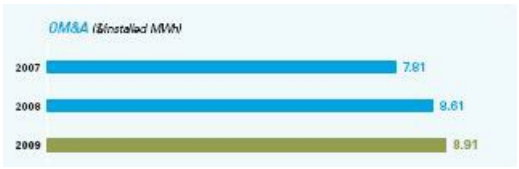


Production for the year ended Dec. 31, 2009 decreased 3,155 gigawatt hours ("GWh") due to higher economic dispatching and higher unplanned outages at Centralia Thermal, higher planned and unplanned outages at Alberta Thermal, lower PPA customer demand at Alberta Thermal and Sheerness, the expiration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

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

Productivity

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



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

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

Safety

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

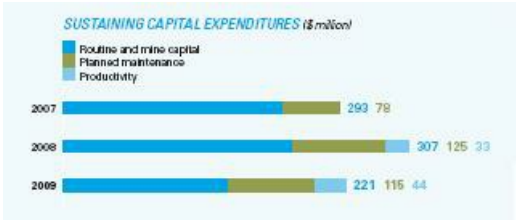
	2007	2008	2009	Target
Injury Frequency Rate	1.76	1.28	**1.41**	1 over next five years

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

Sustaining Capital Expenditures

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

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



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

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

Earnings and Cash Flow From Operating Activities

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

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

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

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

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

In 2009, cash flow from operating activities decreased due to lower cash earnings, the receipt of an additional PPA payment in 2008, higher inventory balances in 2009,

and unfavourable movements in other working capital balances.

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

Investment Grade Ratios

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

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

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

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

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

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

Shareholder Value

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

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

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

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

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

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

RESULTS OF OPERATIONS

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

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

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

HIGHLIGHTS AND SUMMARY OF RESULTS

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

Year ended Dec. 31	2009	2008	2007
Availability (%)	**85.1**	85.8	87.2
Production (GWh)	**45,736**	48,891	50,395
Revenue	**2,770**	3,110	2,775
Gross margin[1]	**1,542**	1,617	1,544
Operating income[1]	**378**	533	541

Net earnings	**181**	235	309
Net earnings per share, basic and diluted	**0.90**	1.18	1.53
Comparable earnings per share	**0.90**	1.46	1.31
Cash flow from operating activities	**580**	1,038	847
Free cash flow[1] (deficiency)	**(117)**	121	111
Cash dividends declared per share	**1.16**	1.08	1.00

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

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

REPORTED EARNINGS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SIGNIFICANT EVENTS

Our consolidated financial results include the following significant events:

2009

Medium-Term Notes Offerings

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

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

Senior Notes Offering

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

Sale of Common Shares

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

Blue Trail

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

Keephills 3

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

Carbon Capture and Storage

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

Acquisition of Canadian Hydro

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

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

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

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

Net Capacity Ownership Interest (MW)

Dec. 31, 2009	Canadian Hydro	TransAlta[1]	TransAlta Consolidated
Western Canada	183	5,059	5,242
Eastern Canada	511	707	1,218

International	–	2,315	2,315
	694	8,081	8,775
Coal	–	4,967	4,967
Natural Gas	–	1,843	1,843
Geothermal	–	164	164
Wind	583	300	883
Hydro	86	807	893
Biomass	25	–	25
	694	8,081	8,775

1 Excluding Canadian Hydro.

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

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

1 Excluding Canadian Hydro.

Sarnia Contract

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

Major Maintenance Plans

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

Normal Course Issuer Bid ("NCIB") Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval to purchase, for cancellation, up to 9.9 million of our common shares representing 5 per cent of our 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition. No purchases were made under the NCIB in 2009.

Chief Operating Officer

On April 28, 2009 we announced the appointment of Dawn Farrell to the position of Chief Operating Officer. In this new role, Ms. Farrell leads our operations, trading, development, commercial, engineering, technology, and procurement activities. Prior to this appointment, Ms. Farrell was Executive Vice President of Commercial Operations and Development.

Additionally, Richard Langhammer, Executive Vice President of Generation Operations, took on a new assignment as Chief Productivity Officer for the remainder of 2009 with the responsibility for identifying strategies to create sustainable costs savings across the Corporation. Mr. Langhammer formally retired at the end of 2009 after 23 years of service.

Ardenville Wind Power Project

On April 28, 2009, we announced plans to design, build, and operate Ardenville, a 69 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the capital cost of the project is the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the remainder of the Ardenville wind project is expected to commence in the first quarter of 2011.

Sundance Unit 4 Derate

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

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

Keephills Units 1 and 2 Uprates

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

Dividend Increase

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

2008

Kent Hills Wind Farm

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

Debentures

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

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

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

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

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

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

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

Genesee 3

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

Mexican Equity Investment

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

LS Power and Global Infrastructure

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

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

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

Potential Breach of Keephills Ash Lagoon

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

Expansion at Summerview

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

Senior Notes Offering

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

Normal Course Issuer Bid Program

On May 5, 2008, we announced plans to renew our NCIB program until May 5, 2009. We received the approval to purchase, for cancellation, up to 19.9 million of our common shares representing 10 per cent of our 199 million common shares issued and outstanding as at April 23, 2008.

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

Uprate at Sundance Facility

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

Greenhouse Gas Emissions

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

Dividend Policy and Dividend Increase

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

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

Blue Trail Wind Power Project

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

2007

Tax Rate Change

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

TransAlta Power, L.P.

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

Ottawa Power Purchase Agreement

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

Mexico Tax Reform

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

NCIB Program

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

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

New Brunswick Power Purchase Agreement

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

Sundance Unit 4 Uprate

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

Greenhouse Gas Emissions Standards

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

Dragline Deposit

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

Keephills 3 Power Plant

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

SUBSEQUENT EVENTS

Summerview 2

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

Kent Hills Expansion

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

DISCUSSION OF SEGMENTED RESULTS

GENERATION: **Owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired plants, and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. At Dec. 31, 2009, Generation had 9,199 MW of gross generating capacity in operation (8,775 MW net ownership interest) and 424 MW net under construction. At Dec. 31, 2009, 1,964 MW net was renewable. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of this MD&A.**

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

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

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

The results of the Generation segment are as follows:

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

Generation Production and Gross Margins

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

Year ended Dec. 31, 2009	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh

Western Canada	**30,443**	**46,334**	**1,182**	**435**	**747**	**25.51**	**9.39**	**16.12**
Eastern Canada	**3,829**	**8,256**	**428**	**225**	**203**	**51.84**	**27.25**	**24.59**
International	**11,464**	**20,276**	**1,113**	**568**	**545**	**54.89**	**28.01**	**26.88**
	45,736	**74,866**	**2,723**	**1,228**	**1,495**	**36.37**	**16.40**	**19.97**

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

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

Western Canada

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

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

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

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

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

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

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

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

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

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

Eastern Canada

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

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

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

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

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

International

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

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

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

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

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

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

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

Operations, Maintenance, and Administration

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

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

Planned Maintenance

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

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

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

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

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

Depreciation Expense

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

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

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

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

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

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

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

Generation.

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

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

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

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

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

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

NET INTEREST EXPENSE

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

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

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

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

OTHER INCOME

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

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

NON-CONTROLLING INTERESTS

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

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

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

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

EQUITY LOSS

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

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

INCOME TAXES

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

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

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

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

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

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

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

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

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

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

FINANCIAL POSITION

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

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

FINANCIAL INSTRUMENTS

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

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

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

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

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

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

Fair Value Hedges

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

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

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

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

1 Option contracts may require an upfront cash investment.

Cash Flow Hedges

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

Project Hedges

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

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

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

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

Commodity Hedges

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

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

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

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

1 Option contracts may require an upfront cash investment.

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

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

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

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

Net Investment Hedges

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

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

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

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

Non-Hedges

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

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

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

Divest contract	ü	–	ü	ü

1 Some contracts may require an initial cash investment.

EMPLOYEE SHARE OWNERSHIP

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

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

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

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

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

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

EMPLOYEE FUTURE BENEFITS

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

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

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

STATEMENTS OF CASH FLOWS

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Debt

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

Credit Facilities

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

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

Share Capital

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

Normal Course Issuer Bid Program

On May 6, 2009, we announced plans to renew our NCIB program until May 6, 2010. We received the approval from the Toronto Stock Exchange to purchase, for cancellation, up to 9.9 million of our common shares representing five per cent of our 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition.

For the year ended Dec. 31, 2009, no shares were purchased under the NCIB program.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, trading activities, hedging activities, and purchase obligations. At Dec. 31, 2009, we provided letters of credit totalling $334 million (2008 – $430 million) and cash collateral of $27 million (2008 – $37 million). The decrease in letters of credit and cash collateral is due primarily to lower forward electricity prices in the Pacific Northwest and reduced trading activity with exchanges. These letters of credit and cash collateral secure certain amounts included on our Consolidated Balance Sheets under “Risk Management Liabilities” and “Asset Retirement Obligation”.

Working Capital

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

Capital Structure

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

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

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

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

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

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

OFF-BALANCE SHEET ARRANGEMENTS

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

CLIMATE CHANGE AND THE ENVIRONMENT

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

Ongoing and Recently Passed Environmental Legislation

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

Canada

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

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

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

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

United States

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

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

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

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

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

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

Legal Implications

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

TransAlta Activities

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

Our environment management programs encompass several elements:

- construction of renewable power sources;
- environmental controls and efficiency improvements;

- active participation in policy discussions;
- clean energy technology development including CCS; and
- investment in an offsets portfolio.

Renewable Power

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

Environmental Controls and Efficiency

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

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

Policy Participation

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

CCS Development

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

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

Offsets Portfolio

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

Future Growth

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

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

2010 OUTLOOK

BUSINESS ENVIRONMENT

Power Prices

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

Environmental Legislation

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

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

Economic Environment

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

A number of our financial and industrial counterparties have experienced credit rating downgrades and we expect 2010 will continue to be challenging for some of our counterparties. While we had no counterparty losses in 2009, we continue to monitor counterparty credit risk and act in accordance with our established risk management

policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

OPERATIONS

Capacity, Production, and Availability

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

Commodity Hedging

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

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

Fuel Costs

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

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

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

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

Operations, Maintenance, and Administration Costs

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

Energy Trading

Earnings from our COD segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading to contribute between $50 million and $70 million in gross margin.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar by offsetting foreign denominated assets with foreign denominated liabilities and foreign exchange contracts. We also have foreign currency expenses, including interest charges, which are used to largely offset our net foreign currency-denominated earnings.

Net Interest Expense

Net interest expense for 2010 is expected to be higher mainly due to higher debt balances and lower interest income. However, changes in interest rates and in the value of the Canadian dollar to the U.S. dollar will affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, there may be the need for additional liquidity. To mitigate this liquidity risk, we expect to maintain $2.1 billion of committed credit facilities, and will monitor our exposures and obligations to ensure we have sufficient liquidity to meet our requirements.

Accounting Estimates

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

CAPITAL EXPENDITURES

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

Growth Capital Expenditures

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

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

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

1 Amounts are shown net of joint venture contributions.

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

Sustaining Capital Expenditures

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

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

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

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

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

Financing

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

RELATED PARTY TRANSACTIONS

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

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

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

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

RISK MANAGEMENT

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

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

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

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

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

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

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

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

RISK CONTROLS

Our risk controls have several key components:

Enterprise Tone

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

Policies

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

Reporting

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

Whistleblower System

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

Value at Risk and Trading Positions

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

over a specified period of time.

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

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

RISK FACTORS

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

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

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

Volume Risk

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

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

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

We manage these risks by:

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

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

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

Generation Equipment and Technology Risk

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

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

We manage our generation equipment and technology risk by:

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

Commodity Price Risk

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

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

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

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

We manage fuel price commodity risk by:

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

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

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

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

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

Fuel Supply Risk

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

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

We manage fuel supply risk by:

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

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

Environmental Risk

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

We manage environmental risk by:

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

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

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

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

Credit Risk

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

We manage our exposure to credit risk by:

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

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

We took steps throughout 2009 to reduce our counterparty risk by proactively assessing the effect of the potential changes in the financial markets on counterparty risk and acting on these assessments. While we had no counterparty losses in 2009, we are continuing to keep a close watch on changes and trends in the market and the impact these changes could have on our trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

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

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

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

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

Currency Rate Risk

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

We manage our currency rate risk by:

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

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

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

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

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide a more reliable and cost effective means to access capital markets through commodity and credit

cycles. We are focused on maintaining a strong balance sheet and stable investment grade credit ratings.

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

We manage liquidity risk by:

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

Interest Rate Risk

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

We manage interest rate risk by:

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

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

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

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

Project Management Risk

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

We attempt to minimize these project risks by:

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

Human Resource Risk

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

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

We manage this risk by:

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

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

Regulatory and Political Risk

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

We manage these risks by working with governments, regulators, and other stakeholders to resolve issues. We are active in policy discussions at a variety of levels. These

stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer-term.

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

Transmission Risk

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

Reputation Risk

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

We manage reputation risk by:

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

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

Corporate Structure Risk

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

General Economic Conditions

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

Income Taxes

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

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

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

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

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings which arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in our favour, we do not believe that the outcome of any claims or potential claims of which we are currently aware will have a material adverse effect on us, taken as a whole.

Other Contingencies

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

These critical accounting estimates are described below.

Revenue Recognition

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

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

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

Financial Instruments

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

Level I

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

Level II

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

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

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

Level III

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

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

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

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

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2009, PP&E makes up 78 per cent of our assets, of which 99 per cent relates to the Generation segment. On an annual basis, and when indicators of impairment exist, we determine whether the net carrying amount of PP&E and associated contracts are recoverable from future undiscounted cash flows. Factors which could indicate that impairment exists include significant underperformance relative to historical or projected operating results, significant changes in the manner or use of the assets, the strategy for our overall business, and significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a

clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

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

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

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

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

Project Development Costs

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

Useful Life of PP&E

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

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

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

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

Valuation of Goodwill

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

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

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

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

Income Taxes

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

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

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

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

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

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

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

Employee Future Benefits

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

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

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

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

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

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

Asset Retirement Obligation

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

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

Sensitivities for the major assumptions are as follows:

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

CURRENT ACCOUNTING CHANGES

Financial Instruments Disclosures

On Oct. 1, 2009, we adopted amendments to Section 3862, Financial Instruments – Disclosures, to converge with *Improving Disclosures about Financial Instruments (Amendments to International Financial Reporting Standard ("IFRS") 7)*. The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. The implementation of this standard did not have an impact upon our consolidated financial statements as the disclosure requirements are already provided as part of our existing financial instrument disclosures.

Financial Instruments–Recognition and Measurement

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

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

Credit Risk

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

Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, we adopted Handbook Section 3064, *Goodwill and Intangible Assets,* replacing Section 3062, *Goodwill and Other Intangible Assets,* and Section 3450, *Research and Development Costs.* Section 3064 further defines that an internally developed intangible asset must demonstrate technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset in order to be able to capitalize associated costs. The implementation of this standard did not have an impact upon our consolidated financial statements.

Mining Exploration Costs

On Jan. 1, 2009, we adopted EIC–174, *Mining Exploration Costs.* EIC–174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have an impact upon our consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Business Combinations and Non-Controlling Interests

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

IFRS Convergence

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

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

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

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

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

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

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

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

NON-GAAP MEASURES

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

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

Net Earnings Reconciliation

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

Year ended Dec. 31	2009	2008	2007

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

Earnings on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Earnings on a comparable basis are calculated using the weighted average common shares outstanding during the year.

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

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

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

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

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

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

Free Cash Flow (Deficiency)

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

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

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

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

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

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

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

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

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

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

Comparable Return on Capital Employed

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

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

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

SELECTED QUARTERLY INFORMATION

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

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

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

CONTROLS AND PROCEDURES

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

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2009, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD LOOKING STATEMENTS

This MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward looking statements. All forward looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management’s experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as “may”, “will”, “believe”, “expect”, “anticipate”, “intend”, “plan”, “foresee”, “potential”, “enable”, “continue” or other comparable terminology. These statements are not guarantees of

our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from those projected.

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

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

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

TransAlta Consolidated Financial Statements

December 31, 2009

MANAGEMENT'S REPORT

To the Shareholders of TransAlta Corporation

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

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

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



STEPHEN G. SNYDER
President & Chief Executive Officer

BRIAN BURDEN
Chief Financial Officer

February 23, 2010

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Shareholders of TransAlta Corporation

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

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

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

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

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

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

of net earnings, respectively, for the year then ended related to Canadian Hydro Developers, Inc.

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

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



STEPHEN G. SNYDER
President & Chief Executive Officer

BRIAN BURDEN
Chief Financial Officer

February 23, 2010

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

To the Shareholders of TransAlta Corporation

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

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

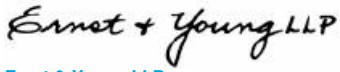
A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's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

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

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

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

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



Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2010

INDEPENDENT AUDITORS' REPORT ON FINANCIAL STATEMENTS

To the Shareholders of TransAlta Corporation

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

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

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

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

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



Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2010

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

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

See accompanying notes.

CONSOLIDATED BALANCE SHEETS

Dec. 31 *(in millions of Canadian dollars)*	2009	2008

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

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

On behalf of the Board:



Donna Soble Kaufman
Director



William D. Anderson
Director

See accompanying notes.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

1 Net of income tax expense of 26 million for the year ended Dec. 31, 2009 (2008 – 61 million recovery, 2007 – 25 million expense).
2 Net of income tax expense of 120 million for the year ended Dec. 31, 2009 (2008 – 129 million expense, 2007 – 16 million recovery).
3 Net of income tax expense of 9 million for the year ended Dec. 31, 2008 (2007 – nil).
4 Net of income tax recovery of 4 million for the year ended Dec. 31, 2009 (2008 – nil, 2007 – nil).
5 Net of income tax recovery of 69 million for the year ended Dec. 31, 2009 (2008 – 30 million expense, 2007 – 7 million expense).

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Description of the Business

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

The two reportable segments of the Corporation are as follows:

I. Generation

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

the sale of electricity, steam, gas, and ancillary services.

II. Commercial Operations & Development ("COD")

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

B. Consolidation

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

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

C. Use of Estimates

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

D. Revenue Recognition

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

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

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

E. Foreign Currency Translation

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

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

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

F. Financial Instruments and Hedges

I. Financial Instruments

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

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

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

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

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

re-measured at fair value at each balance sheet date.

II. Hedges

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

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

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

a. Fair Value Hedges

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

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

b. Cash Flow Hedges

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

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

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

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

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

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

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

G. Cash and Cash Equivalents

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

H. Collateral Paid and Received

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

I. Inventory

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

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

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

J. Property, Plant, and Equipment

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

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

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

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

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

K. Goodwill

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

L. Intangible Assets

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

M. Project Development Costs

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

N. Income Taxes

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

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

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

O. Employee Future Benefits

The Corporation accrues its obligations under employee benefit plans and the related costs, net of plan assets. The cost of pensions and other post-employment and post-retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. The defined benefit pension plans are based on an employee's final average earnings and years of service. The expected return on plan assets is based on expected future capital market returns. The discount rate used to

calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. As the members of the Canadian Registered Plan are now almost all inactive, the past service costs from plan amendments and the excess of the net cumulative unamortized actuarial gain or loss over 10 per cent of the greater of the accrued benefit obligation and the market value of plan assets are amortized over the Estimated Average Remaining Life ("EARL"). When the restructuring of a benefit plan gives rise to both a curtailment and settlement of obligations, the curtailment is accounted for prior to the settlement. Transition obligations and assets arising from the prospective adoption of new accounting standards are amortized over EARL. This method has not been applied to the Centralia plan as it did not qualify because the majority of its members are still active. The U.S. plan is amortized using Estimated Average Remaining Service Life ("EARSL").

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

P. Long-Term Debt

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

Q. Asset Retirement Obligation ("ARO")

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

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

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

R. Stock-Based Compensation Plans

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

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

S. Accounting for Emission Credits and Allowances

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

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

T. Planned Maintenance

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

U. Business Combinations

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

2. ACCOUNTING CHANGES

A. Current Year Reclassifications

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

I. Classification of Pension Assets

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

II. Classification of Collateral

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

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

III. Classification of Mining Development Costs

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

IV. Classification of Debt

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

B. Current Year Accounting Changes

I. Financial Instruments – Disclosures

On Oct. 1, 2009, the Corporation adopted amendments to Section 3862, *Financial Instruments – Disclosures,* to converge with *Improving Disclosures about Financial Instruments (Amendments to IFRS 7)*. The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. The implementation of this standard did not have an impact upon the consolidated financial statements as the disclosure requirements are already provided as part of the Corporation's existing financial instrument disclosures.

II. Financial Instruments – Recognition and Measurement

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

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

III. Credit Risk

On Jan. 1, 2009, the Corporation adopted the Emerging Issues Committee ("EIC") Abstract 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC – 173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Disclosure required as a result of adopting this standard can be found in Note 9.

IV. Deferral of Costs and Internally Developed Intangibles

On Jan. 1, 2009, the Corporation adopted Handbook Section 3064, *Goodwill and Intangible Assets,* replacing Section 3062, *Goodwill and Other Intangible Assets,* and Section 3450, *Research and Development Costs*. Section 3064 further defines that an internally developed intangible asset must demonstrate technical feasibility, an intention for use or sale, the generation of future economic benefits, and adequate access to resources to complete the development of the intangible asset in order to be able to capitalize associated costs. The implementation of this standard did not have an impact upon the consolidated financial statements.

V. Mining Exploration Costs

On Jan. 1, 2009, the Corporation adopted EIC – 174, *Mining Exploration Costs*. EIC – 174 provides guidance on the capitalization of mining exploration costs, particularly when mining reserves have not been proven. The EIC also defines when an impairment test should be performed on previously capitalized costs. The implementation of this standard did not have an impact upon the consolidated financial statements.

C. Prior Year Accounting Changes

I. Employee Future Benefits

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

II. Financial Instruments

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

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

III. Comprehensive Income

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

IV. Financial Instruments – Recognition and Measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities, and non-financial derivatives. It requires that financial assets and

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

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

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

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

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

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

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

V. Hedges

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

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

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

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

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

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

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

D. Future Accounting Changes

I. Business Combinations and Non-Controlling Interests

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

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

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

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

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

3. WRITEDOWN OF MINING DEVELOPMENT COSTS

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

4. OTHER INCOME

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

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

5. NON-CONTROLLING INTERESTS

A. Consolidated Statements of Earnings

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

B. Consolidated Balance Sheets

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

The change in non-controlling interests is outlined below:

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

C. Consolidated Statements of Cash Flows

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

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

6. INCOME TAXES

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2009	2008	2007
Earnings before income taxes	**196**	258	329
Equity loss	**–**	(97)	(50)
Earnings before income taxes and equity loss	**196**	355	379
Statutory Canadian federal and provincial income tax rate (%)	**29**	30	32
Expected income tax expense	**57**	105	121

Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(29)**	(24)	(36)
Resolution of uncertain tax positions	**–**	(15)	(18)
Tax recovery on sale of Mexican equity investment *(Note 24)*	**–**	(35)	–
Capital taxes	**1**	1	2
Effect of tax rate changes	**(6)**	–	(48)
Statutory and other rate differences	**(4)**	(7)	(1)
Other	**(4)**	(2)	–
Income tax expense	**15**	23	20
Effective tax rate (%)	**8**	6	5

II. Components of Income Tax Expense

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

B. Consolidated Balance Sheets

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

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

7. FINANCIAL INSTRUMENTS

A. Analysis of Financial Assets and Liabilities by Measurement Basis

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost *(Note 1 (F))*. The following table analyses the carrying amounts of the financial assets and liabilities by category:

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

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

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

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	50	–	50
Accounts receivable	–	–	505	–	505
Collateral paid	–	–	37	–	37
Risk management assets					
Current	121	79	–	–	200
Long-term	220	1	–	–	221
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	658	658
Collateral received	–	–	–	24	24
Risk management liabilities					
Current	74	74	–	–	148
Long-term	96	6	–	–	102
Long-term debt recourse[1]	–	–	–	2,543	2,543
Long-term debt non-recourse[1]	–	–	–	265	265

1 Includes current portion.

B. Fair Value of Financial Instruments

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

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

I. Level Determinations and Classifications

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

Level I

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

Level II

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

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

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

Level III

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

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

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

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

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

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

	Fair value[1]				Total carrying
As at Dec. 31, 2008	Level I	Level II	Level III	Total	value
Financial assets and liabilities measured at fair value					
Net risk management assets [2]	1	170	–	171	171
Financial assets and liabilities measured at other than fair value					
Long-term debt	–	2,542	–	2,542	2,808

1 Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, collateral paid, accounts payable and accrued liabilities, and collateral received).

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

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

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

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

Where the fair values have been developed using valuation models based on unobservable or internally developed assumptions or inputs (Level III Energy Trading Risk Management fair values), the key inputs include historical data such as plant performance, volatilities and correlations between products derived from historical prices, congestion on transmission paths, or demand profiles for individual non-standard deals and structured products. In limited circumstances, an internally-developed fundamental price forecast is used when commodity transactions extend into periods for which market-observable prices are not available.

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

The total change in fair value estimated using a valuation technique with unobservable inputs, for financial assets and liabilities measured and recorded at fair value, that was recognized in pre-tax net earnings for the year ended Dec. 31, 2009 was a $1 million gain (2008–$16 million gain). A reconciliation of the movements in risk management fair values by Level, as well as additional Level III gain (loss) information can be found in Note 9.

C. Inception Gains and Losses

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

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

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

D. Nature and Extent of Risks Arising from Financial Instruments

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

I. Market Risk

a. Commodity Price Risk

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

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

i. Commodity Price Risk — Proprietary Trading

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

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

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

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

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

ii. Commodity Price Risk — Generation

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

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

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

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

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

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

b. Interest Rate Risk

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

The possible effect on net earnings and OCI for the years ended Dec. 31, 2009, 2008, and 2007, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading and hedging interest rate derivatives outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is the most reasonably possible change in market interest rates over the next quarter and is consistent with a +/– one standard deviation move from the mean.

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

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

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, and the U. S., and Australian dollars, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

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

The possible effect on net earnings and OCI for the years ended Dec, 31, 2009, 2008, and 2007, due to changes in the exchange rates associated with financial instruments outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is consistent with a +/- one standard deviation move from the mean.

Year ended Dec. 31	2009		2008		2007	
Currency	Net earnings decrease[1]	OCI gain[1, 2]	Net earnings decrease[1]	OCI gain[1, 2]	Net earnings decrease[1]	OCI gain[1, 2]
U.S.	4	**2**	4	2	–	4
AUD	**1**	**–**	2	–	1	–
Euro	–	**–**	–	3	1	2
Total	5	**2**	6	5	2	6

1 These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
2 The foreign exchange impact related to financial instruments used as the hedging instruments in the net investment hedges have been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Generation PPAs as receivables are substantially all secured by letters of credit.

At Dec. 31, 2009, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at year-end.

The Corporation's maximum exposure to credit risk at Dec. 31, 2009, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading positions, net of any collateral held, at Dec. 31, 2009 was $63 million (2008 - $105 million).

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

Per cent (%)	Investment grade	Non-investment grade	Total
Accounts receivable	92	8	**100**
Risk management assets	100	–	**100**

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in Note 8.

At Dec. 31, 2009, the Corporation did not have any significant past due trade receivables.

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used in proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong balance sheet and stable investment grade credit ratings.

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

TransAlta manages liquidity risk by monitoring liquidity on trading positions, preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital, reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Exposure Management Committee, senior management, and Board of Directors, and maintaining investment grade credit ratings.

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

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Accounts payable and accrued liabilities	521	—	—	—	—	—	521
Collateral received	86	—	—	—	—	—	86
Debt[1]	29	251	1,090	659	231	2,203	4,463
Energy Trading risk management (assets) liabilities [2]	(112)	(103)	(76)	(12)	1	31	(271)
Other risk management liabilities (assets) [2]	15	(7)	—	—	—	18	26
Interest on long-term debt	224	203	183	170	142	600	1,522
Total	**763**	**344**	**1,197**	**817**	**374**	**2,852**	**6,347**

1 Excludes impact of hedge accounting and includes credit facilities that are currently scheduled to mature in 2012 and 2013.
2 Net risk management assets and liabilities (Note 9).

E. Financial Instruments Provided as Collateral

At Dec. 31, 2009, $45 million (2008 — $63 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Gen have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

At Dec. 31, 2009, the Corporation provided $27 million (2008 — $37 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

F. Financial Assets Held as Collateral

At Dec. 31, 2009, the Corporation received $86 million (2008 — $24 million) in cash as collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

G. Gains and Losses on Financial Instruments

The Corporation's COD segment utilizes a variety of derivatives in its proprietary trading activities, including certain commodity hedging activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the year ended Dec. 31, 2009, the COD segment recognized a net unrealized loss of $6 million (2008 – $2 million net unrealized loss, 2007 – $3 million net unrealized loss).

The Corporation's Generation segment utilizes a variety of derivatives in its operations, including certain commodity hedges that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting as well as other contracting activities, and the related assets and liabilities are classified as held for trading. The net unrealized gains or losses from changes in the fair value of derivatives are reported as revenue in the period the change occurs. For the year ended Dec. 31, 2009, the Generation segment recognized a net unrealized gain of $3 million (2008 – $12 million net unrealized loss, 2007 – $30 million net unrealized loss).

Net interest expense as reported on the Consolidated Statements of Earnings includes interest income and expense, respectively, on the Corporation's interest-bearing financial assets, primarily cash, and its interest-bearing financial liabilities, primarily long-term debt. Interest expense is calculated using the effective interest method *(Note 17)*. Interest rate derivatives that are not designated as hedges are classified as held for trading and are marked-to-market each reporting period with the net gain or loss recorded in net interest expense.

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

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

The table below outlines the net realized and unrealized gains and losses included in net earnings that are associated with derivatives not designated as hedges:

Year ended Dec. 31	2009	2008	2007
Foreign exchange derivatives (losses) gains	**(1)**	11	4
Interest rate derivatives losses	**–**	–	2
Other derivatives gains	**–**	1	–

8. ACCOUNTS RECEIVABLE

As at Dec. 31	2009	2008
Gross accounts receivable	**470**	562

Allowance for doubtful accounts *(Note 28)*	**(49)**	(57)
Net accounts receivable	**421**	505

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2008	57
Change in foreign exchange rates	(8)
Balance, Dec. 31, 2009	**49**

9. RISK MANAGEMENT ASSETS AND LIABILITIES

Risk management assets and liabilities are comprised of two major types: (1) those that are used in the COD and Generation segments in relation to trading activities and certain contracting activities ("Energy Trading") and (2) those used in hedging non-Energy Trading transactions, such as debt, and the net investment in self-sustaining foreign subsidiaries ("other risk management assets and liabilities").

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

As at Dec. 31	2009			2008		
Balance Sheet–Totals	**Energy Trading**	**Other**	**Total**	**Energy Trading**	**Other**	**Total**
Risk management assets						
Current	**144**	**–**	**144**	176	24	200
Long-term	**207**	**17**	**224**	187	34	221
Risk management liabilities						
Current	**30**	**15**	**45**	142	6	148
Long-term	**50**	**28**	**78**	57	45	102
Net risk management assets (liabilities)	**271**	**(26)**	**245**	164	7	171

Energy Trading

The values of risk management assets and liabilities for Energy Trading are included on the Consolidated Balance Sheets as follows:

As at Dec. 31	2009			2008
Balance Sheet–EnergyTrading	**Hedges**	**Non-hedges**	**Total**	**Total**
Risk management assets				
Current	**130**	**14**	**144**	176
Long-term	**202**	**5**	**207**	187
Risk management liabilities				
Current	**15**	**15**	**30**	142
Long-term	**47**	**3**	**50**	57
Net risk management assets	**270**	**1**	**271**	164

The following table illustrates the disclosure on the movements in the fair value of the Corporation's Energy Trading net risk management assets and liabilities separately by source of valuation during the year ended Dec. 31, 2009:

	Hedges			Non-hedges			Total		
	Level I	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**	**Level I**	**Level II**	**Level III**
Net risk management assets at Dec. 31, 2008	–	163	–	1	–	–	1	163	–
Changes attributable to:									
Acquisition of Canadian Hydro *(Note 24)*	–	–	(31)	–	–	–	–	–	(31)
Commodity price changes	–	147	–	–	(2)	–	–	145	–
New contracts entered	–	37	(1)	–	–	1	–	37	–
Contracts settled	–	(20)	–	(1)	2	–	(1)	(18)	–
Change in foreign exchange rates	–	(25)	–	–	–	–	–	(25)	–
Transfers in/out of Level III	–	(5)	5	–	–	–	–	(5)	5
Net risk management assets (liabilities) at Dec. 31, 2009	**–**	**297**	**(27)**	**–**	**–**	**1**	**–**	**297**	**(26)**
Additional Level III gain(loss) information:									
Change in fair value included in OCI			4			–			4
Unrealized gain(loss) included in earnings before income taxes relating to those net assets held at Dec. 31, 2009			–			1			1

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

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

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	110	99	76	13	(1)	–	297
	Level III	3	3	(1)	(1)	–	(31)	(27)
Non-hedges	Level I	–	–	–	–	–	–	–
	Level II	(2)	1	1	–	–	–	–
	Level III	1	–	–	–	–	–	1
Total	Level I	–	–	–	–	–	–	–
	Level II	108	100	77	13	(1)	–	297
	Level III	4	3	(1)	(1)	–	(31)	(26)
Total net assets (liabilities)		**112**	**103**	**76**	**12**	**(1)**	**(31)**	**271**

The Corporation's outstanding Energy Trading derivative financial instruments at Dec. 31, 2009, were as follows:

Units (000s)	Electricity (MWh)	Natural gas (GJ)	Transmission (MWh)	Oil (gallons)
Derivative financial instruments designated as hedges				
Notional Amounts				
Purchases	–	360	–	25,074
Sales	175,756	2,163	–	–
Derivative financial instruments held for trading (non-hedges)				
Notional Amounts				
Purchases	14,844	309,764	4,852	–
Sales	14,107	323,793	–	–

Other Risk Management Assets and Liabilities

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

As at Dec. 31	2009			2008
Balance Sheet–Other	Hedges	Non-hedges	Total	Total
Risk management assets				
Current	**–**	**–**	**–**	24
Long-term	**17**	**–**	**17**	34
Risk management liabilities				
Current	**13**	**2**	**15**	6
Long-term	**28**	**–**	**28**	45
Net risk management (liabilities) assets	**(24)**	**(2)**	**(26)**	7

The following table illustrates the disclosure on the movements in the fair value of the Corporation's other net risk management assets and liabilities separately by source of valuation during the year ended Dec. 31, 2009:

	Hedges	Non-hedges	Total
Net risk management assets (liabilities) at Dec. 31, 2008	8	(1)	7
Changes in net asset value attributable to:			
Market price changes	(20)	–	(20)
New contracts entered	(38)	(2)	(40)
Contracts settled	26	1	27
Net risk management liabilities at Dec. 31, 2009	**(24)**	**(2)**	**(26)**

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

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

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	(13)	7	–	–	–	(18)	(24)
Non-hedges	(2)	–	–	–	–	–	(2)
Total net (liabilities) assets	(15)	7	–	–	–	(18)	(26)

Additional information related to other risk management assets and liabilities designated as hedges and non-hedges are outlined below:

A. Hedges

I. Hedges of Foreign Operations

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

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

a. Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	AUD34	**(2)**	**2010**	AUD34	2	2009

b. Foreign Currency Contracts

Outstanding foreign currency forward sales (purchase) contracts are as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	AUD120	**(2)**	**2010**	AUD108	(1)	2009
	U.S.182	**(1)**	**2010**	U.S.(107)	(1)	2009

II. Hedges of Future Foreign Currency Obligations

a. Foreign Exchange Forward Contract

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

As at Dec. 31	2009				2008			
	Amount sold	Amount purchased	Fair value liability	Maturity	Amount sold	Amount purchased	Fair value asset	Maturity
	91	**U.S.78**	**(8)**	**2010**	51	U.S.48	8	2009–2010

U.S.14	**15**	**–**	**2010**	–	–	–	–
AUD4	**U.S.3**	**–**	**2010**	–	–	–	–
–	**–**	**–**	**–**	84	EUR57	13	2009

b. Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	U.S.(500)	**(16)**	**2015**	–	–	–

III. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 5.75 per cent to 6.65 per cent, to floating rate debt through interest rate swaps as shown below:

As at Dec. 31	2009			2008		
	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value asset	Maturity
	100	**7**	**2011**	100	12	2011
	U.S.50	**(1)**	**2013**	–	–	–
	U.S.150	**7**	**2018**	U.S.100	21	2018

Including the interest rate swaps above, 31 per cent of the Corporation's debt is subject to floating interest rates as at Dec. 31, 2009 (2008–24 per cent).

The Corporation also has an outstanding forward start interest rate swap that converts floating rate debt into fixed rate debt. The commencement date for this swap is March 5, 2010, with fixed rates ranging from 3.5 per cent to 4.6 per cent, as shown below:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	U.S.300	**(8)**	**2020**	U.S.300	(46)	2019

B. Non-Hedges

I. Cross-Currency Interest Rate Swaps

Cross-currency interest rate swaps are periodically entered into in order to limit the Corporation's exposure to fluctuations in foreign exchange and interest rates. The (liability) asset resulting from an outstanding cross-currency interest rate swap is as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value asset	Maturity
	AUD13	**(2)**	**2010**	AUD41	1	2009

II. Foreign Currency Contracts

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

Outstanding notional amounts and fair values with these foreign currency forward sales (purchases) are as follows:

As at Dec. 31	2009			2008		
	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	U.S.13	**–**	**2010**	U.S.90	(2)	2009

III. Total Return Swaps

The Corporation also has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been pursued. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter *(Note 7).*

C. Contingent Features in Derivative Instruments

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

As at Dec. 31, 2009 the Corporation had posted collateral of $37 million in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at Dec. 31, 2009, the Corporation would be required to post an additional $29 million of collateral to its counterparties.

10. HEDGING ACTIVITIES

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

A. Fair Value Hedges

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

No ineffective portion of fair value hedges was recorded in 2009, 2008, or 2007.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings:

Year ended Dec. 31		2009	2008	2007
Instruments in fair value hedging relationships	Location of gain (loss) on the Consolidated Statements of Earnings			
Interest rate contracts	Net interest expense	**20**	(26)	(34)
Long-term debt	Net interest expense	**(20)**	26	34
Net earnings impact		**–**	–	–

B. Cash Flow Hedges

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

For the year ended Dec. 31, 2009, a pre-tax unrealized gain of $400 million (2008–gain of $327 million, 2007–loss of $57 million) was recorded in OCI for the effective portion of the cash flow hedges, and a pre-tax total of $204 million (2008–$91 million, 2007–$25 million) related to amounts previously related to OCI was reclassified to net earnings. For the year ended Dec. 31, 2009, a realized loss of $2 million (2008–nil, 2007–nil), was recognized in net earnings for ineffectiveness.

Over the next 12 months, the Corporation estimates that $77 million (2008–$17 million after-tax losses) of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. In addition, it is the Corporation's intent to settle a substantial portion of the cash flow hedges by physical delivery of the underlying commodity, resulting in gross settlement at the contract price. These contracts are designated as all-in-one hedges and are required to be accounted for as cash flow hedges.

The following tables summarize the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income, Consolidated Statements of Earnings, and the Consolidated Balance Sheets:

Year ended Dec. 31, 2009

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of gain (loss) reclassified from OCI	Pre-tax gain (loss) reclassified from OCI	Location of loss recognized in earnings	Pre-tax loss recognized in earnings
Interest rate	**37**	Net interest expense	**1**	Net interest expense	**2**
Foreign exchange	**(31)**	Foreign exchange	**–**		
		Property, plant, and equipment	**(15)**		
Commodity	**394**	Revenue	**(205)**		
OCI impact	**400**	**OCI impact**	**(219)**	**Earnings impact**	**2**

Year ended Dec. 31, 2008

	Effective portion		
Derivatives in cash flow hedging relationships	Pre-tax (loss) gain recognized in OCI	Location of gain reclassified from OCI	Pre-tax gain reclassified from OCI
Interest rate	(56)	Net interest expense	–
Foreign exchange	31	Foreign exchange	–
		Property, plant, and equipment	8
Commodity	352	Revenue	91
OCI impact	327	OCI impact	99

Year ended Dec. 31, 2007

	Effective portion		
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (loss) gain reclassified from OCI	Pre-tax (loss) gain reclassified from OCI
Interest rate	9	Net interest expense	(5)
Foreign exchange	(10)	Foreign exchange	–
		Property, plant, and equipment	1
Commodity	(56)	Revenue	30
OCI impact	(57)	OCI impact	26

C. Net Investment Hedges

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

For the year ended Dec. 31, 2009, a net after-tax loss of $69 million (2008–gain of $47 million, 2007–gain of $19 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income:

Derivatives in net investment hedging	Pre-tax (losses) gains recognized in OCI for the year ended	Pre-tax losses recognized in OCI for the year ended	Pre-tax (losses) gains recognized in OCI for the year ended

relationships	Dec. 31, 2009	Dec. 31, 2008	Dec. 31, 2007
Foreign exchange	**(64)**	(37)	(2)
Cross currency	**(3)**	(62)	152
Long-term debt	**233**	(257)	90
OCI impact	**166**	(356)	240

Summary

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

As at Dec. 31	2009					2008
	Fair Value Hedges	Cash Flow Hedges	Net Investment Hedges	Not Designated as a Hedge	Total	Total
Financial derivative assets						
Energy Trading	**–**	**332**	**–**	**19**	**351**	363
Non-Energy Trading	**14**	**3**	**–**	**–**	**17**	58
Total	**14**	**335**	**–**	**19**	**368**	421
Financial derivative liabilities						
Energy Trading	**–**	**62**	**–**	**18**	**80**	199
Non-Energy Trading	**1**	**35**	**5**	**2**	**43**	51
Total	**1**	**97**	**5**	**20**	**123**	250

Additional information on derivative instruments has been presented on a net basis in Note 9.

11. INVENTORY

Inventory includes coal, natural gas, and emission credits which are valued at the lower of cost and net realizable value.

As at Dec. 31	2009	2008
Coal	**86**	45
Natural gas	**4**	5
Purchased emission credits	**–**	1
Total	**90**	51

The increase in coal inventory in 2009 compared to 2008 is primarily due to lower production at the Centralia and Alberta Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2008	51
Net additions	44
Change in foreign exchange rates	(5)
Balance, Dec. 31, 2009	**90**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2009 and 2008, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

12. LONG-TERM RECEIVABLE

In 2008, the Corporation received a notice of reassessment from the federal taxation authority in Canada related to the disposal of the Transmission Business in the 2002 taxation year. As a result of the reassessment, the Corporation was required by law to pay approximately $49 million in taxes plus interest and penalties notwithstanding the Corporation's ability to challenge this reassessment. The Corporation funded a portion of this amount in 2008 by transferring $8 million from its tax prepayment account. Additional cash payments and a loss carryback were applied in 2009 to fund the remaining balance. The Corporation is in the process of challenging this reassessment. Since it is anticipated that the dispute will not be resolved within one year, these prepayments have been recorded as a long-term receivable.

13. PROPERTY, PLANT, AND EQUIPMENT

As at Dec. 31		2009			2008		
	Depreciable lives	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation equipment	**3–50**	**4,709**	**2,267**	**2,442**	4,835	1,993	2,842
Mining property & equipment	**4–50**	**795**	**415**	**380**	776	352	424
Gas generation	**2–30**	**2,135**	**883**	**1,252**	2,244	1,030	1,214
Geothermal generation	**10–20**	**333**	**101**	**232**	386	87	299
Hydro generation	**3–60**	**611**	**172**	**439**	399	226	173
Wind generation	**30**	**1,556**	**125**	**1,431**	375	39	336
Biomass	**15–30**	**25**	**1**	**24**	–	–	–
Capital spares and other	**2–15**	**270**	**65**	**205**	228	68	160
Assets under construction	**–**	**1,038**	**–**	**1,038**	443	–	443
Coal rights[1]	**–**	**133**	**86**	**47**	134	83	51
Land	**–**	**68**	**–**	**68**	63	–	63
Transmission systems	**15–50**	**48**	**28**	**20**	49	20	29
Total		**11,721**	**4,143**	**7,578**	9,932	3,898	6,034

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

The Corporation capitalized $36 million of interest to PP&E in 2008 (2008 – $21 million, 2007 – $6 million).

The change in PP&E is outlined below:

	Cost	Accumulated depreciation and amortization	Net book value
Balance, Dec. 31, 2008	9,932	3,898	6,034
Acquisition of Canadian Hydro *(Note 24)*	1,291	–	1,291
Additions	904	–	904
Disposals	(10)	(6)	(4)
Depreciation	–	463	(463)
Change in foreign exchange rates	(273)	(94)	(179)
Retirement of assets	(132)	(118)	(14)
Transfers	9	–	9
Balance, Dec. 31, 2009	**11,721**	**4,143**	**7,578**

14. GOODWILL

The change in goodwill is outlined below:

Balance, Dec. 31, 2008	142
Acquisition of Canadian Hydro *(Note 24)*	304
Change in foreign exchange rates	(12)
Balance, Dec. 31, 2009	**434**

A portion of goodwill in Generation is related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars *(Note 29)*. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

15. INTANGIBLE ASSETS

The change in intangible assets is outlined below:

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2008	499	286	213
Acquisition of Canadian Hydro *(Note 24)*	176	–	176
Change in foreign exchange rates	(68)	(43)	(25)
Amortization	–	31	(31)
Balance, Dec. 31, 2009	**607**	**274**	**333**

A portion of intangible assets are related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

16. OTHER ASSETS

As at Dec. 31	2009	2008
Deferred license fees	**22**	21
Accrued pension benefit asset *(Note 31)*	**18**	9
Project development costs	**45**	4
Keephills 3 transmission deposit	**8**	–
Other	**9**	5
Total other assets	**102**	39

Deferred license fees consist primarily of a license to lease the land on which certain generating assets are located, and are being amortized on a straight-line basis over the useful life of the generating assets to which the license relates.

The Keephills 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit for Keephills 3. The full amount of the deposit is anticipated to be reimbursed over the next 10 years, as long as certain performance criteria are met.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects.

17. LONG-TERM DEBT AND NET INTEREST EXPENSE

A. Amounts Outstanding

As at Dec. 31	2009			2008		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**1,063**	**1,063**	**1.0%**	443	443	2.8%
Debentures, due 2011 to 2030	**1,055**	**1,076**	**6.7%**	682	681	6.8%
Senior notes[3]	**1,687**	**1,684**	**5.9%**	1,352	1,344	6.3%
Non-recourse	**578**	**581**	**6.3%**	265	265	7.4%
Other	**59**	**59**	**6.7%**	66	66	6.7%
	4,442	**4,463**		2,808	2,799	
Less: current portion	**(31)**	**(31)**		(244)	(244)	
Total long-term debt	**4,411**	**4,432**		2,564	2,555	

1 Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
2 Composed of Bankers' Acceptances and other commercial borrowings under long-term committed credit facilities.
3 2009–U.S.$1,600 million, 2008-U.S.$1,100 million.

A portion of the fixed rate components of debentures and senior notes have been hedged using fixed to floating interest rate swaps and therefore the Corporation has included the fair value of these swaps with the value of the debt. Non-recourse debt is not hedged and therefore recorded at cost.

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's businesses. The facility is a five-year revolver which was last renewed in May 2007 and matures in 2012. The U.S.$300 million committed facility is a five-year facility that matures in 2013. Interest rates on the credit facilities vary depending on the option selected; Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities all of which mature in 2011.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent. The Corporation has converted $100 million fixed interest rate debt with a rate of 6.9 per cent to floating rates through the use of interest rate swaps (Note 9). These interest rate swaps mature in 2011. During 2009, the Corporation issued a total of $600 million in debentures; $200 million was issued in May 2009 at a fixed interest rate of 6.45 per cent, maturing in 2014 and $400 million was issued in November 2009 at a fixed rate of 6.4 per cent, maturing in 2019.

Senior Notes U.S.$300 million of the senior notes bear an interest rate of 5.75 per cent and mature in 2013 and another U.S.$300 million bear an interest rate of 6.75 per cent and mature in 2012. U.S.$500 million bear interest at 6.65 per cent and mature in 2018, and the remaining U.S.$500 million of the senior notes were issued in November 2009 and bear an interest rate of 4.75 per cent and mature in 2015. In addition, the Corporation converted U.S.$50 million and U.S.$150 million fixed interest rate debt with rates of 5.8 per cent and 6.7 per cent, respectively, to floating rates through the use of interest rate swaps (Note 9). These interest rate swaps mature in 2013 and 2018, respectively. A total of U.S.$1,100 million of the senior notes has been designated as a hedge of the Corporation's net investment of U.S. self-sustaining foreign operations.

Non-Recourse Debt consists of project financing debt, debt securities and senior secured bonds of CE Gen, debt related to the Wailuku River Hydroelectric L.P ("Wailuku") acquisition, and debentures issued by Canadian Hydro. The CE Gen related assets have been pledged as security for the project financing debt. The CE Gen debt has maturity dates ranging from 2010 to 2018 and interest rates ranging from 7.5 per cent to 8.3 per cent. This debt is recorded at cost; the fair value as at Dec. 31, 2009 was U.S.$184 million (2008–U.S.$208 million). Wailuku debt at Dec. 31, 2009 has a cost of U.S.$8 million (2008–U.S.$9 million) and bears interest at a floating rate currently of 1.2 per cent. The Canadian Hydro debt has maturity dates ranging from 2010 to 2018 and interest rates ranging from 5.3 per cent to 10.9 per cent and includes debt with a cost of $355 million and U.S.$20 million. This debt is recorded at cost; the fair value as at Dec. 31, 2009 was $376 million.

Other consist of notes payable for the Windsor Plant which bears interest at fixed rates and are recourse to the Corporation through a standby letter of credit. These mature in November 2014. Also included is a commercial loan obligation which bears an interest rate of 5.9 per cent and will mature in 2023. This is an unsecured loan and requires annual payments of interest and principal.

B. Principal Repayments

2010	29
2011	251
2012	1,090
2013	659
2014	231
2015 and thereafter	2,203
Total(1)	**4,463**

1 Excludes impact of derivatives and include credit facilities that are currently scheduled to mature in 2012 and 2013.

C. Interest Expense

Year ended Dec. 31	2009	2008	2007
Interest on long-term debt	**183**	177	171
Interest income	**(6)**	(46)	(32)
Capitalized interest	**(36)**	(21)	(6)
Other	**3**	–	–
Net interest expense	**144**	110	133

The Corporation capitalizes interest during the construction phase of longer-term capital projects. The capitalized interest in 2009 relates primarily to Keephills 3 and associated mine capital, Blue Trail, and Summerview II. In 2008 the capitalized interest related to the Corporation's investment in Keephills 3 and associated mine capital, Kent Hills, Summerview, and Blue Trail.

In 2008, an appeal was resolved pertaining to the timing of revenue recognition and deductions on previous years' tax returns based on applicable income tax laws. Consequently, a $30 million interest refund from taxation authorities was recorded as interest income.

D. Guarantees

I. Letters of Credit

Letters of credit are issued to counterparties under some contractual arrangements with certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Balance Sheets. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at Dec. 31, 2009 totalled $334 million (2008–$430 million) with nil (2008–nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.1 billion of committed credit facilities of which $0.7 billion is not drawn and is available as of Dec. 31, 2009, subject to customary borrowing conditions.

18. ASSET RETIREMENT OBLIGATION

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

Balance, Dec. 31, 2008	297
Liabilities incurred in period	3
Liabilities settled in period	(35)
Accretion expense	24
Revisions in estimated cash flows	10
Acquisition of Canadian Hydro *(Note 24)*	3
Change in foreign exchange rates	(20)
	282
Less: current portion	(32)
Balance, Dec. 31, 2009	**250**

The Corporation has a right to recover a portion of future asset retirement costs.

TransAlta estimates that the undiscounted amount of cash flow required to settle the asset retirement obligation is approximately $0.8 billion which will be incurred between 2010 and 2072. The majority of the costs will be incurred between 2020 and 2030. An average discount rate of eight per cent and an inflation rate of two per cent were used to calculate the carrying value of the asset retirement obligation. At Dec. 31, 2009, the Corporation had provided a surety bond in the amount of U.S.$192 million (2008–U.S.$192 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2009, the Corporation had provided letters of credit in the amount of $67 million (2008–$57 million) in support of future retirement obligations at the Alberta mines.

19. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

As at Dec. 31	2009	2008
Deferred coal revenues *(Note 25)*	**51**	31
Sale of emission credits	**1**	7
Power purchase arrangement in limited partnership	**21**	23
Accrued benefit liability *(Note 31)*	**49**	49
Other	**14**	21
Total deferred credits and other long-term liabilities	**136**	131

The power purchase arrangement in the limited partnership represents the fair value adjustments for the Sheerness Generating Station to deliver power at less than the prevailing market price at the time of the acquisition of the plant by TransAlta Cogeneration, L.P. (“TA Cogen”). The power purchase arrangement is amortized on a straight-line basis over the life of the contract.

20. COMMON SHARES

A. Issued and Outstanding

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

Year ended Dec. 31	2009		2008	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**197.6**	**1,761**	200.9	1,781
Issued under stock option plans	**–**	**–**	0.4	8
Issued under Performance Share Ownership Plan	**0.2**	**6**	0.2	7
Shares purchased under NCIB *(Note 21)*	**–**	**–**	(3.9)	(35)
Issued, net of tax[1]	**20.6**	**402**	–	–
Issued and outstanding, end of year	**218.4**	**2,169**	197.6	1,761

1 Net of issuance costs of $16 million and tax expense of $4 million.

At Dec. 31, 2009 the Corporation had 1.5 million outstanding employee stock options (2008 – 1.7 million). For the year ended Dec. 31, 2009, no options were exercised.

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Corporation’s Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. The plan is put before the shareholders every three years for approval, and was last approved on April 26, 2007.

When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation’s common shares, other than by way of a Permitted Bid, where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

C. Dividend Reinvestment and Share Purchase (“DRASP”) Plan

Under the terms of the DRASP plan, participants are able to purchase additional common shares by reinvesting dividends. Shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the Toronto Stock Exchange on the investment dates.

D. Earnings Per Share (“EPS”)

Year ended Dec. 31	2009	2008	2007
Net earnings	**181**	235	309
Basic and diluted weighted average number of common shares outstanding	**201**	199	202
Earnings per share			
Basic and diluted	**0.90**	1.18	1.53

The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding *(Note 30)*.

21. SHAREHOLDERS' EQUITY

	Common shares	Retained earnings	Accumulated other comprehensive income/(loss)	Total shareholders' equity
Balance, Dec. 31, 2008	1,761	688	61	2,510
Net earnings	–	181	–	181
Common shares issued	408	–	–	408
Dividends declared		(235)		(235)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	–	–	(69)	(69)
Gains on derivatives designated as cash flow hedges, net of tax	–	–	280	280
Derivatives designated as cash flow hedges in prior periods transferred to the Consolidated Balance Sheets and net earnings in the current period, net of tax	–	–	(146)	(146)
Balance, Dec. 31, 2009	**2,169**	**634**	**126**	**2,929**

Components of AOCI

As at Dec. 31	2009	2008
Cumulative unrealized (losses) gains on translating self-sustaining foreign operations, net of hedges and of tax	**(63)**	6
Cumulative unrealized gains on cash flow hedges, net of tax	**189**	55
Total accumulated other comprehensive income	**126**	61

Normal Course Issuer Bid ("NCIB") program

On May 6, 2009, TransAlta announced plans to renew the NCIB program until May 6, 2010. The Corporation received the approval to purchase, for cancellation, up to 9.9 million of its common shares representing five per cent of the 198 million common shares issued and outstanding as at April 30, 2009. Any purchases undertaken will be made on the open market through the Toronto Stock Exchange at the market price of such shares at the time of acquisition.

No purchases were made under the NCIB program in 2009.

For the year ended Dec. 31, 2008, TransAlta purchased 3,886,400 shares at an average price of $33.46 per share for a total of $130 million. For the year ended Dec. 31, 2007, TransAlta purchased 2,371,800 shares at an average of $31.59 per share for a total of $75 million.

22. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

Year ended Dec. 31	2009	2008	2007
Source (use):			
Accounts receivable	114	80	44
Prepaid expenses	**(7)**	3	(3)
Income taxes receivable	**(1)**	(20)	(29)
Inventory	**(42)**	(10)	22
Accounts payable and accrued liabilities	**(208)**	157	32
Income taxes payable	**(5)**	–	–
Change in non-cash operating working capital	**(149)**	210	66

23. CAPITAL

TransAlta's components of capital are listed below:

As at Dec. 31	2009	2008	Increase/ (decrease)
Current portion of long-term debt	**31**	244	(213)
Less: cash and cash equivalents	**(82)**	(50)	(32)
	(51)	194	(245)
Long-term debt			
Recourse	**3,857**	2,332	1,525
Non-recourse	**554**	232	322
Non-controlling interests	**478**	469	9
Common shareholders' equity			
Common shares	**2,169**	1,761	408
Retained earnings	**634**	688	(54)
AOCI	**126**	61	65
	7,818	5,543	2,275
Total capital	**7,767**	5,737	2,030

The long-term portion of recourse debt increased from Dec. 31, 2008 as a result of the issuance of senior notes and debentures primarily related to the acquisition of Canadian Hydro. This increase in long-term debt was partially offset by scheduled repayments and changes in exchange rates.

TransAlta's strategy for managing capital remained unchanged from Dec. 31, 2008.

TransAlta's objectives in managing capital are to:

A. Maintain an Investment Grade Credit Rating:

The Corporation operates in a long-cycle and capital intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable rates. TransAlta monitors key capital ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and manages capital in line with those expectations:

Cash flow to interest coverage Cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest

income. TransAlta targets this ratio to be in a range of four to five times.

Cash flow to debt Cash flow from operating activities before changes in working capital divided by average total debt. TransAlta targets this ratio to be 20 to 25 per cent.

Debt to invested capital Debt less cash and cash equivalents divided by debt, non-controlling interests, and shareholders' equity less cash and cash equivalents. TransAlta targets this ratio to be 55 to 60 per cent.

These ratios are presented below:

Year ended Dec. 31	2009	2008
Cash flow to interest coverage (times) [1]	**4.9**	7.2
Cash flow to debt (%) [1]	**20.1**	31.1
Debt to invested capital (%)	**56.1**	48.1

1 Last 12 months.

The decrease in cash flow to interest coverage resulted from decreased cash flows from operating activities and higher interest expense. The decrease in cash flow to debt resulted from a decrease in cash flows from operating activities and an increase in debt balances *(Note 17)*. The increase in debt to invested capital resulted from an increase in debt balances *(Note 17)*. TransAlta routinely monitors forecasts for net earnings, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Capital Assets:

These amounts are summarized in the table below:

Year ended Dec. 31	2009	2008	Increase/ (decrease)
Cash flow from operating activities	**580**	1,038	(458)
Dividends paid	**(226)**	(212)	(14)
Capital asset expenditures	**(904)**	(1,006)	102
Net cash outflow	**(550)**	(180)	(370)

The decrease in the total net cash flows primarily resulted from lower cash flows from operating activities. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2009, $0.7 billion of the Corporation's available credit facilities were not drawn.

While any of the existing debentures are outstanding, the Corporation will not issue or in any other manner become liable for any indebtedness, unless the aggregate principal amount of the Corporation's indebtedness, as defined in the Corporation's trust indenture, does not exceed 75 per cent of total capital.

TransAlta's credit facilities are unsecured and provide funds in either Canadian or U.S. currencies. They contain standard terms and conditions including covenants with respect to financial leverage and cash flow coverage that would be considered typical of bank credit facilities of this nature.

During 2009, the Corporation issued a total of $600 million in debentures; $200 million was issued in May 2009 at a fixed interest rate of 6.45 per cent, maturing in 2014 and $400 million was issued in November 2009 at a fixed rate of 6.4 per cent, maturing in 2019. Both issuances have financial terms and conditions similar to the other debentures of the Corporation. The financial terms and conditions of all other debentures remain unchanged from Dec. 31, 2008. During 2009, the Corporation also issued U.S.$500 million in senior notes at an interest rate of 4.75 per cent and mature in 2015.

During 2009, the Corporation issued 20.8 million common shares for total net proceeds of $408 million.

TransAlta's formal dividend policy targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable net earnings. TransAlta's management defines comparable net earnings as net earnings adjusted for items that would not be considered to be part of normal operations.

24. ACQUISITIONS AND DISPOSALS

A. Acquisitions

On Oct. 23, 2009, TransAlta acquired 87 per cent of Canadian Hydro through the purchase of the issued and outstanding shares of Canadian Hydro. On Nov. 4, 2009, TransAlta acquired the remaining 13 per cent of the issued and outstanding shares. The total cash consideration was $785 million. The results of Canadian Hydro are included in the consolidated financial statements of the Corporation from the acquisition date of Oct. 23, 2009.

The details of the cash consideration are as follows:

Total shares acquired (millions)	143.8
Price per share	5.25
Total consideration paid	755
Transaction costs	30
Total cash consideration	**785**

The allocation of the aggregate purchase price based on the estimated fair values of the assets of Canadian Hydro on the acquisition date is as follows:

Assets:	
Cash	19
Accounts receivable	25
Prepaid expenses	5
Property, plant, and equipment	1,291

Intangible assets	176	
Development costs	22	
Goodwill	304	
Total assets acquired		1,842
Liabilities:		
Accounts payable and accrued liabilities	54	
Current risk management liabilities	6	
Long-term risk management liabilities	34	
Long-term debt	931	
Future income tax liabilities	29	
Asset retirement obligation	3	
Total liabilities assumed		1,057
Total purchase price		**785**

The long-term risk management liabilities consist of financial contracts used to hedge exposures to fluctuations in electricity prices. These contracts qualify for hedge accounting treatment.

Although TransAlta does not anticipate material changes to this preliminary allocation, the values may change when the evaluation of fair value information is complete. Any subsequent adjustments will be accounted for in the period incurred.

B. Disposals

On Oct. 8, 2008, TransAlta successfully completed the sale of the Mexican equity investment to InterGen for a sale price of $334 million. The sale included the plants at both facilities and all associated commercial arrangements.

The details of the sale are as follows:

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

Included in the book value of the investment is a provision for representations and warranties of $2 million (2008–$ 13 million).

During 2007, the Mexican equity investment incurred a loss of $50 million.

25. RELATED PARTY TRANSACTIONS

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

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

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

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

26. CONTINGENCIES

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

27. COMMITMENTS

The Corporation has entered into a number of long-term gas purchase agreements, transportation and transmission agreements, royalty and right-of-way agreements in the normal course of operations.

Approximate future payments under the fixed price purchase contracts, transmission, operating leases, mining agreements, interest on long-term debt, and growth project commitments are as follows:

	Fixed price gas purchase contracts	Transmission	Operating leases	Coal supply and mining agreements	Long-term service agreement	Interest on long-term debt[1]	Growth project commitments	Total
2010	8	–	10	51	14	224	497	804
2011	7	2	10	47	16	203	87	372
2012	7	3	9	47	16	183	14	279
2013	7	3	9	47	16	170	–	252
2014	7	3	8	51	16	142	–	227
2015 and thereafter	25	38	56	269	18	600	–	1,006
Total	**61**	**49**	**102**	**512**	**96**	**1,522**	**598**	**2,940**

1 Includes impact of derivatives.

A. Fixed Price Gas Purchase Contracts

Centralia Gas and the Corporation's Australia operations have contracts in place for the fixed portion of the gas costs at the plants.

B. Transmission

During 2008, TransAlta entered into several five-year agreements with Bonneville Power Administration Transmission ("BPAT") to purchase 400 megawatts ("MW") of Pacific Northwest transmission network capacity. Provided BPAT can meet certain conditions for delivering the service, the Corporation is committed to taking the services at BPAT's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Operating Leases

TransAlta has operating leases in place for buildings, vehicles and various types of equipment.

D. Coal Supply and Mining Agreements

At Centralia Thermal, a significant portion of production is subject to short- to medium-term energy sales contracts. Centralia Thermal also has various coal supply and associated rail transport contracts to provide coal for use in production. During 2008, TransAlta entered into various coal supply agreements with three suppliers for the Centralia Thermal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates ranging from June 1, 2008 to Dec. 31, 2013.

At Alberta Thermal, the mines are operated by a third party who is paid a fixed amount to provide a budgeted supply of coal.

E. Long-Term Service Agreements

TransAlta has various service agreements in place primarily for repairs and maintenance that may be required on turbines at various wind generating facilities.

F. Growth Project Commitments

On Jan. 11, 2010, TransAlta announced the expansion of its existing 96 MW Kent Hills wind facility. The capital cost of the project is estimated at $100 million and is expected to begin commercial operations by the end of 2010. As at Dec. 31, 2009 total capital incurred on this project was $18 million. Natural Forces will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

As part of the acquisition of Canadian Hydro on Oct. 23, 2009, TransAlta assumed the plans to design, build, and operate Bone Creek, an 18 MW hydro facility in British Columbia. The capital cost of the project is estimated at $48 million and is expected to begin commercial operations in the first quarter of 2011. As at Dec. 31, 2009, the total capital incurred on this project was $4 million.

On April 28, 2009, TransAlta announced plans to design, build, and operate Ardenville, a 69 MW wind power project in southern Alberta. The capital cost of the project is estimated at $135 million. Included in the purchase was an operational 3 MW wind power project in southern Alberta. As at Dec. 31, 2009, the total capital incurred on this project was $27 million. Commercial operations of the remainder of the facility are expected to commence in the first quarter of 2011.

On Jan. 29, 2009, TransAlta announced two efficiency uprates at its Keephills plant in Alberta. Both Keephills units 1 and 2 will be upgraded by 23 MW each, to a total of 450 MW, and are expected to be operational by the end of 2011 and 2012, respectively. The capital cost of the projects is estimated at $68 million. As at Dec. 31, 2009, the total capital incurred on these projects was $2 million.

On May 27, 2008, TransAlta announced a 66 MW expansion of its Summerview wind farm located in southern Alberta near Pincher Creek. The capital cost of the project is estimated at $123 million with construction commencing in the second quarter of 2009 and commercial operations expected to begin in the first quarter of 2010. As at Dec. 31, 2009, total capital spend on this project was $106 million. Commercial operations commenced on Feb. 23, 2010 and the total capital cost of the project was $123 million *(Note 33).*

Keephills 3 plant construction and associated mine capital costs are anticipated to be approximately $1.9 billion with final payments for goods and services due by 2011. TransAlta's proportionate share is approximately $988 million. As at Dec. 31, 2009, total spend on this project was $707 million.

On June 21, 2007, TAGP entered into an agreement with Bucyrus Canada Limited and Bucyrus International Inc. for the purchase of a dragline to be used primarily in the supply of coal to the Keephills 3 joint venture project. The total dragline purchase costs include approximately $121 million for the purchase of the equipment, and an additional $29 million for the assembly and commissioning of the dragline, for a total of approximately $150 million, with final payments for goods and services due by completion and acceptance of the asset in the third quarter of 2010. As at Dec. 31, 2009, total payments under this agreement were $125 million.

Growth project commitments are as follows:

	Kent Hills	Bone Creek	Ardenville	Keephills Unit 1 uprate	Keephills Unit 2 uprate	Summerview	Keephills Unit 3	Total

2010	82	44	108	3	5	17	238	497
2011	–	–	–	30	14	–	43	87
2012	–	–	–	–	14	–	–	14
2013	–	–	–	–	–	–	–	–
2014	–	–	–	–	–	–	–	–
2015 and thereafter	–	–	–	–	–	–	–	–
Total	**82**	**44**	**108**	**33**	**33**	**17**	**281**	**598**

G. Other

A significant portion of the Corporation's electricity and thermal sales revenues are subject to PPAs and long-term contracts. Commencing Jan. 1, 2001, a large portion of Alberta's coal generating assets became subject to long-term PPAs for a period approximating the remaining life of each plant or unit. These PPAs set a production requirement and availability target for each plant or unit and the price at which each MWh will be supplied to the customer. Remaining coal capacity in Alberta is sold on the open electricity market.

A portion of Poplar Creek's electrical and all of its steam capacity is committed to the customer under a long-term contract. The remaining electrical capacity may be taken by the customer at market prices or sold on the open electricity market by TransAlta. Other gas-fired facilities in Alberta supply steam and/or electricity to specified customers under long-term contracts with additional requirements for availability, reliability, and other plant-specific performance measures.

Sarnia has 20-year contracts with a customer group with three five-year options for extensions to the contracts. The contracts allow for up to 40 per cent of the plant's maximum capacity. These contracts set payments for peak MWs, total MWhs supplied to the customers and steam consumed, while TransAlta assumes the availability and heat rate risk. On Sept. 30, 2009, TransAlta signed a new agreement with the Ontario Power Authority to supply up to 444 MWs of electricity to the Ontario electricity market, which was effective on July 1, 2009 and expires on Dec. 31, 2025. The remaining capacity at Sarnia is available for export to the merchant market, based on market prices. Electrical production at the remaining Ontario plants is subject to contracts expiring in three to eight years.

Mississauga, Windsor-Essex, and Ottawa have contracts that set availability targets and the price at which the plant will be paid per MWh produced, as well as risk sharing of fuel costs based on market prices. Thermal energy contracts for Mississauga and Windsor expire at the same time as the energy production contracts and are with a different customer base. Ottawa has thermal contracts with three different customers. The contract with the main customer expires at the end of 2022. These contracts set payments for volumes consumed, while TA Cogen assumes the heat rate risk. On Oct. 12, 2007, the Corporation signed an agreement amending the original PPA with the Ontario Electricity Financial Corporation ("OEFC") for the Ottawa Cogeneration Power Plant. The agreement was entered into to ensure continued plant production following the expiry of long-term natural gas supply contracts. The agreement is in effect from Nov. 1, 2007 until Dec. 31, 2012.

28. PRIOR PERIOD REGULATORY DECISION

In response to a complaint filed by San Diego Gas & Electric Company under Section 206 of the Federal Power Act ("FPA"), the Federal Energy Regulatory Commission ("FERC") established a claim of approximately U.S.$46 million in refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange ("PX") and the California Independent System Operator ("ISO") during the Oct. 2, 2000 through June 20, 2001 period (the "Main Refund Transactions"). TransAlta has provided U.S.$46 million to account for refund liabilities relating to Main Refund Transactions. TransAlta filed a cost-of-service-based petition for relief from these refund obligations. FERC rejected TransAlta's relief petition. On Dec. 1, 2006, TransAlta filed for rehearing of FERC's rejection. On Aug. 24, 2007, the U.S. Court of Appeals for the Ninth Circuit granted the appeal. TransAlta has requested a rehearing; however, FERC has yet to make a ruling on such a request and such a decision is not expected in the near future.

During settlement negotiations, the California parties have sought to obtain refunds for two sets of transactions beyond the Main Refund Transactions. The first set includes sales made by sellers in the PX and ISO markets in the period May 1 to Oct. 1, 2001 (the "Summer Transactions"). The other set includes bilateral transactions between all sellers and a component of the California Department of Water Resources ("CDWR") referred to as CERS (the "CERS Transactions"). FERC has specifically rejected attempts to introduce refunds for the Summer and CERS Transactions. Nonetheless, the California parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. The Ninth Circuit held that FERC's authorization of market-based rate tariffs in these proceedings complied with the FPA, but that FERC erred in refusing refunds on the grounds that it lacked authority to order refunds for violations of its reporting requirement and remanded the case for further refund proceedings. The court did not itself order any refunds, leaving it to FERC to consider appropriate remedial options.

On March 21, 2008, FERC issued an Order on Remand establishing a refund hearing before an Administrative Law Judge to determine whether any individual public utility seller's violation of FERC's market-based rate quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable in California during the 2000–2001 period. The California parties appealed FERC's basis for determining refund liability but the appeal was denied by FERC on Oct. 6, 2008. The California Parties have sought rehearing of FERC's refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. In a decision issued Aug. 24, 2007, which denied rehearing remanded matters to FERC, the Ninth Circuit ruled that FERC had properly excluded both the Summer Transactions and the CERS Transactions from the complaint proceeding. FERC has yet to respond to the remand.

TransAlta does not presently believe the California parties will be successful in obtaining refunds alleged for the Summer and CERS transactions. TransAlta has not made any provision for such alleged refunds at this time.

29. SEGMENT DISCLOSURES

A. Description of Reportable Segments

The Corporation has two reportable segments as described in Note 1.

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

Generation expenses include COD's intersegment charge for energy marketing and financial risk management services in the amount of $32 million (2008–$30 million, 2007–$27 million). COD's operating expenses are presented net of these intersegment charges.

The accounting policies of the segments are the same as those described in Note 1. Intersegment transactions are accounted for on a cost-recovery basis that approximates market rates.

B. Reported Segment Earnings and Segment Assets

I. Earnings information

Year ended Dec. 31, 2009	Generation	COD	Corporate	Total
Revenues	**2,723**	**47**	**–**	**2,770**
Fuel and purchased power	**(1,228)**	**–**	**–**	**(1,228)**
	1,495	**47**	**–**	**1,542**
Operations, maintenance, and administration	**550**	**31**	**86**	**667**
Depreciation and amortization	**453**	**4**	**18**	**475**
Taxes, other than income taxes	**22**	**–**	**–**	**22**
Intersegment cost allocation	**32**	**(32)**	**–**	**–**
	1,057	**3**	**104**	**1,164**
	438	**44**	**(104)**	**378**
Foreign exchange gain *(Note 7)*				**8**
Writedown of mining development costs *(Note 3)*				**(16)**
Net interest expense *(Notes 7 and 17)*				**(144)**
Other income *(Note 4)*				**8**
Earnings before non-controlling interests and income taxes				**234**

Year ended Dec. 31, 2008	Generation	COD	Corporate	Total
Revenues	3,005	105	–	3,110
Fuel and purchased power	(1,493)	–	–	(1,493)
	1,512	105	–	1,617
Operations, maintenance, and administration	487	53	97	637
Depreciation and amortization	409	3	16	428
Taxes, other than income taxes	19	–	–	19
Intersegment cost allocation	30	(30)	–	–
	945	26	113	1,084
	567	79	(113)	533
Foreign exchange loss *(Note 7)*				(12)
Net interest expense *(Notes 7 and 17)*				(110)
Equity loss *(Note 24)*				(97)
Other income *(Note 4)*				5
Earnings before non-controlling interests and income taxes				319

Year ended Dec. 31, 2007	Generation	COD	Corporate	Total
Revenues	2,720	55	–	2,775
Fuel and purchased power	(1,231)	–	–	(1,231)
	1,489	55	–	1,544
Operations, maintenance, and administration	447	34	96	577
Depreciation and amortization	391	1	14	406
Taxes, other than income taxes	20	–	–	20
Intersegment cost allocation	27	(27)	–	–
	885	8	110	1,003
	604	47	(110)	541
Foreign exchange gain *(Note 7)*				3
Net interest expense *(Notes 7 and 17)*				(133)
Equity loss *(Note 24)*				(50)
Other income *(Note 4)*				16
Earnings before non-controlling interests and income taxes				377

Included above in Generation is $9 million (2008–$5 million, 2007–$5 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

II. Selected Consolidated Balance Sheets information

As at Dec. 31, 2009	Generation	COD	Corporate	Total
Goodwill *(Note 14)*	**404**	**30**	**–**	**434**
Total segment assets	**9,133**	**148**	**481**	**9,762**
As at Dec. 31, 2008				
Goodwill *(Note 14)*	112	30	–	142
Total segment assets	7,119	206	499	7,824

A portion of goodwill is related to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars. Unrealized foreign exchange gains and losses related to the translation of self-sustaining foreign operations do not affect net earnings and as such translation gains and losses are reflected in AOCI.

III. Selected Consolidated Statements of Cash Flows information

Year ended Dec. 31, 2009	Generation	COD	Corporate	Total
Capital expenditures	**879**	**5**	**20**	**904**
Year ended Dec. 31, 2008				
Capital expenditures	992	7	7	1,006
Year ended Dec. 31, 2007				
Capital expenditures	577	5	17	599

IV. Depreciation and amortization on the Consolidated Statements of Cash Flows

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

Year ended Dec. 31	2009	2008	2007
Depreciation and amortization expense on the Consolidated Statements of Earnings	**475**	428	406
Depreciation included in fuel and purchased power	**40**	38	30
Accretion expense included in depreciation and amortization expense	**(24)**	(22)	(24)
Other	**2**	7	3
Depreciation and amortization on the Consolidated Statements of Cash Flows	**493**	451	415

C. Geographic Information

I. Revenues

Year ended Dec. 31	2009	2008	2007
Canada	**1,631**	1,839	1,742
U.S.	**1,042**	1,165	932
Australia	**97**	106	101
Total revenue	**2,770**	3,110	2,775

II. Property, Plant, and Equipment and Goodwill

	Property, Plant, and Equipment *(Note 13)*		Goodwill *(Note 14)*	
As at Dec. 31	2009	2008	2009	2008
Canada	**6,220**	4,464	**360**	57
U.S.	**1,182**	1,418	**74**	85
Australia	**176**	152	**–**	–
Total	**7,578**	6,034	**434**	142

A change in foreign exchange rates from 2008 to 2009 has resulted in a $179 million decrease in net book value of PP&E and a $12 million decrease in goodwill. The change in foreign exchange rates related to translation of self-sustaining foreign operations does not affect net earnings; rather any cumulative translation gains and losses are reflected in AOCI.

30. STOCK-BASED COMPENSATION PLANS

At Dec. 31, 2009, the Corporation had two types of stock-based compensation plans and an employee share purchase plan.

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

A. Fixed Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada at or below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

II. U.S. Plan

This plan mirrors the rules of the Canadian plan.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia, excluding directors and officers. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

The total options outstanding and exercisable under these fixed stock option plans at Dec. 31, 2009 are shown below:

	Options outstanding			Options exercisable	
Range of exercise prices (per share)	Number outstanding at Dec. 31, 2009 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price (per share)	Number exercisable at Dec. 31, 2009 (millions)	Weighted average exercise price (per share)
11.47–17.70	0.2	2.9	14.81	0.2	14.81
17.71–23.94	0.4	4.2	18.81	0.4	18.81
23.95–30.18	0.1	1.3	27.70	0.1	27.70
30.19–36.41	0.8	8.1	32.29	0.2	32.29
11.47–36.41	1.5	5.9	26.36	0.9	22.28

The change in the number of options outstanding under the fixed option plans are outlined below:

Year ended Dec. 31	2009		2008		2007	
	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)	Number of share options (millions)	Weighted average exercise price (per share)
Outstanding, beginning of year	**1.7**	**26.80**	1.2	19.69	2.2	20.20
Granted	**–**	**–**	1.0	32.10	–	–
Exercised	**–**	**–**	(0.3)	20.52	(0.8)	21.39
Cancelled or expired	**(0.2)**	**26.47**	(0.2)	27.96	(0.2)	17.52
Outstanding, end of year	**1.5**	**26.36**	1.7	26.80	1.2	19.69

B. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to grant to employees and directors up to an aggregate of 4.0 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, can not exceed 13.0 million common shares. Participants in the PSOP receive grants which, after three years, make them eligible to receive a set number of common shares or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. Once a participant's PSOP eligibility has been established, 50 per cent of the shares may be released to the participant, while the remaining 50 per cent will be held in trust for one additional year. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the Corporation's common shares amongst the companies comprising the comparator group. Expense related to this plan is recorded during the period earned, with the corresponding payable recorded in liabilities.

Year ended Dec. 31 (millions)	2009	2008	2007
Number of awards outstanding, beginning of year	**0.9**	1.0	1.2
Granted	**0.5**	0.2	0.4
Exercised	**(0.2)**	(0.2)	(0.1)
Cancelled or expired	**(0.2)**	(0.1)	(0.5)
Number of awards outstanding, end of year	**1.0**	0.9	1.0

In 2009, PSOP compensation expense was $7 million after-tax (2008–$5 million after-tax, 2007–$7 million after-tax), which is included in OM&A expense in the Consolidated Statements of Earnings. In 2009, 224,591 common shares were issued at $22.08 per share. In 2008, 221,855 common shares were issued at $24.30 per share. In 2007, 103,896 common shares were issued at $33.35 per share.

C. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are not eligible for this program in accordance with the Sarbanes-Oxley legislation. The Corporation will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2009, accounts receivable from employees under the plan totalled $3 million (2008–$3 million).

D. Stock-Based Compensation

At Dec. 31, 2009, the Corporation had 1.5 million outstanding employee stock options (2008–1.7 million).

The Corporation uses the fair value method of accounting for awards granted under its fixed stock option plans.

The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model in 2008 and the binomial model in 2005 and 2002 using the following assumptions:

	2008	2005	2002
Weighted average fair value per option	6.31	6.84	4.25
Risk-free interest rate (%)	3.6	4.3	5.9
Expected life of the options (years)	7	10	7
Dividend rate (%)	3.4	5.6	4.9
Volatility in the price of the Corporation's shares (%)	23.2	47.0	28.3

31. EMPLOYEE FUTURE BENEFITS

A. Description

The Corporation has registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. The defined benefit option of the registered pension plans has been closed for new employees for all periods presented.

The latest actuarial valuations for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2009. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2009. The last actuarial valuation for funding purposes of the registered plan was Dec. 31, 2007, and the effective date of the next required valuation for funding purposes is Dec. 31, 2010. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $58 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members (other post-employment benefits) and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2007. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2009.

B. Costs Recognized

The costs recognized during the year on the defined benefit, defined contribution, and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Current service cost	**2**	**1**	**2**	**5**
Interest cost	**22**	**3**	**2**	**27**
Actual return on plan assets	**(38)**	–	–	**(38)**
Actuarial loss	**36**	**7**	**13**	**56**
Difference between expected return and actual return on plan assets	**19**	–	–	**19**
Difference between amortized and actuarial gain on accrued benefit obligation for the year	**(33)**	**(6)**	**(12)**	**(51)**
Amortization of net transition asset	**(9)**	–	–	**(9)**
Defined benefit (income) expense	**(1)**	**5**	**5**	**9**
Defined contribution option expense of registered pension plan	**18**	–	–	**18**
Net expense	**17**	**5**	**5**	**27**

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Current service cost	3	1	1	5
Interest cost	20	3	1	24
Actual return on plan assets	55	–	–	55
Actuarial gain	(49)	(5)	(4)	(58)
Difference between expected return and actual return on plan assets	(79)	–	–	(79)
Difference between amortized and actuarial loss on accrued benefit obligation for the year	50	6	5	61
Past service costs	–	2	–	2
Difference between amortized and actual plan amendments of past service costs for the year	–	(2)	–	(2)
Amortization of net transition asset	(9)	–	–	(9)
Defined benefit (income) expense	(9)	5	3	(1)
Defined contribution option expense of registered pension plan	17	–	–	17
Net expense	8	5	3	16

Year ended Dec. 31, 2007	Registered	Supplemental	Other	Total
Current service cost	4	2	1	7
Interest cost	19	2	2	23
Actual return on plan assets	(10)	–	–	(10)
Actuarial (gain) loss	(15)	6	(2)	(11)
Difference between expected return and actual return on plan assets	(15)	–	–	(15)
Difference between amortized and actuarial loss (gain) on accrued benefit obligation for the year	16	(4)	2	14
Amortization of net transition asset	(9)	–	–	(9)
Defined benefit (income) expense	(10)	6	3	(1)
Defined contribution option expense of registered pension plan	15	–	–	15
Net expense	5	6	3	14

In 2009, 2008, and 2007, the entire net expense is related to continuing operations.

C. Status of Plans

The status of the defined benefit and other health and dental benefit plans is as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Fair value of plan assets	**299**	**3**	–	**302**
Accrued benefit obligation	**358**	**55**	**33**	**446**
Funded status–plan deficit	**(59)**	**(52)**	**(33)**	**(144)**
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	**1**	**2**	**2**	**5**
Unamortized transition (asset) obligation	**(9)**	**1**	–	**(8)**
Unamortized net actuarial gains	**85**	**15**	**11**	**111**
Total recognized in the consolidated financial statements:				
Accrued benefit asset (liability)	**18**	**(34)**	**(20)**	**(36)**
Amortization period in years	**14**	**14**	**15**	

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Fair value of plan assets	279	3	–	282
Accrued benefit obligation	324	47	20	391
Funded status–plan deficit	(45)	(44)	(20)	(109)
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	**–**	1	3	4
Unamortized transition (asset) obligation	(18)	1	**–**	(17)
Unamortized net actuarial gains	72	9	**–**	81
Total recognized in the consolidated financial statements:				
Accrued benefit liability	9	(33)	(17)	(41)
Amortization period in years	15	13	15	

The current portion of the accrued benefit liability is included in accounts payable and accrued liabilities on the Consolidated Balance Sheets. The long-term portion is included in other assets and deferred credits and other long-term liabilities.

Year ended Dec. 31, 2009	Registered	Supplemental	Other	Total
Accrued current liabilities	**–**	**3**	**2**	**5**
Other long-term (assets) liabilities	**(18)**	**31**	**18**	**31**
Accrued benefit (asset) liability	**(18)**	**34**	**20**	**36**

Year ended Dec. 31, 2008	Registered	Supplemental	Other	Total
Accrued current liabilities	–	–	1	1
Other long-term (assets) liabilities	(9)	33	16	40
Accrued benefit (asset) liability	(9)	33	17	41

D. Contributions

Expected cash flows on the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Employer contributions				
2010 (expected)	6	3	3	12
Expected benefit payments				
2010	26	3	3	32
2011	27	3	3	33
2012	27	3	3	33
2013	27	3	3	33

2014	28	3	3	34
2015–2019	141	18	14	173

E. Plan Assets

The plan assets of the defined benefit and other health and dental benefit plans are as follows:

	Registered	Supplemental	Other	Total
Fair value of plan assets at Dec. 31, 2007	356	2	–	358
Contributions	3	4	2	9
Benefits paid	(27)	(3)	(2)	(32)
Effect of translation on U.S. plans	2	–	–	2
Actual return on plan assets [1]	(55)	–	–	(55)
Fair value of plan assets at Dec. 31, 2008	279	3	–	282
Contributions	7	3	2	12
Benefits paid	(26)	(3)	(2)	(31)
Benefits transferred in [2]	4	–	–	4
Effect of translation on U.S. plans	(3)	–	–	(3)
Actual return on plan assets [1]	38	–	–	38
Fair value of plan assets at Dec. 31, 2009	**299**	**3**	**–**	**302**

1 Net of expenses.
2 Transfer of pension assets for addition of employees.

The Corporation's investment policy is to seek a consistently high investment return over time while maintaining an acceptable level of risk to satisfy the benefit obligations of the pension plans. The goal is to maintain a long-term rate of return on the fund that at least equals the growth of liabilities, currently seven per cent. The pension fund may be invested in a variety of permitted investments including publicly traded common or preferred shares, rights or warrants, convertible debentures or preferred securities, bonds, debentures, mortgages, notes or other debt instruments of government agencies or corporations, private company securities, guaranteed investment contracts, term deposits, cash or money market securities, and mutual or pooled funds eligible for pension fund investment. The targeted asset allocation is 50 per cent equity and 50 per cent fixed income. Cash and money market instruments may be held from time-to-time as short-term investments or as defensive reserves within the portfolios of each asset class. The fund may invest in derivatives for the purpose of hedging the portfolio or altering the desired mix of the fund. Derivative transactions that leverage the fund in any way are not permitted without the specific approval of the Corporation's Pension Committee.

The allocation of defined benefit plan assets by major asset category at Dec. 31, 2009 and 2008 is as follows:

Year ended Dec. 31, 2009	Registered	Supplemental
Equity securities	**52%**	**–**
Debt securities	**45%**	**–**
Cash and cash equivalents	**3%**	**100%**
Total	**100%**	**100%**

Year ended Dec. 31, 2008	Registered	Supplemental
Equity securities	51%	–
Debt securities	48%	–
Cash and cash equivalents	1%	100%
Total	100%	100%

Plan assets do not include any common shares of the Corporation at Dec. 31, 2009. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2009 (2008 – $0.1 million).

The fair value of the total defined benefit plan assets by major asset category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	132	11	12	155
Debt securities	125	11	–	136
Cash and cash equivalents	11	–	–	11
Total	**268**	**22**	**12**	**302**

The fair value of the Canadian defined benefit plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	132	–	12	144
Debt securities	125	–	–	125
Cash and cash equivalents	7	–	–	7
Total	**264**	**–**	**12**	**276**

The fair value of the U.S. defined benefit plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total
Equity securities	–	11	–	11
Debt securities	–	11	–	11
Cash and cash equivalents	1	–	–	1
Total	**1**	**22**	**–**	**23**

The fair value of the supplemental plan assets by major category at Dec. 31, 2009 is as follows:

Year ended Dec. 31, 2009	Level I	Level II	Level III	Total

Equity securities	–	–	–	–
Debt securities	–	–	–	–
Cash and cash equivalents	3	–	–	3
Total	**3**	**–**	**–**	**3**

F. Accrued Benefit Obligation

The accrued benefit obligation on the defined benefit and other health and dental benefit plans is as follows:

	Registered	Supplemental	Other	Total
Accrued benefit obligation as at Dec. 31, 2007	373	49	23	**445**
Current service cost	3	1	1	**5**
Past service cost	–	2	–	**2**
Interest cost	20	3	1	**24**
Benefits paid	(27)	(3)	(2)	**(32)**
Effect of translation on U.S. plans	4	–	1	**5**
Actuarial gain	(49)	(5)	(4)	**(58)**
Accrued benefit obligation as at Dec. 31, 2008	324	47	20	**391**
Current service cost	2	1	2	**5**
Interest cost	22	3	2	**27**
Benefits paid	(26)	(3)	(2)	**(31)**
Benefits transferred in[1]	4	–	–	**4**
Effect of translation on U.S. plans	(4)	–	(2)	**(6)**
Actuarial loss	36	7	13	**56**
Accrued benefit obligation as at Dec. 31, 2009	**358**	**55**	**33**	**446**

1 Transfer of accrued benefit obligation for addition of employees.

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligation on the defined benefit and other health and dental benefit plans are as follows:

Year ended Dec. 31, 2009	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	**6.0**	**6.0**	**5.7**
Rate of compensation increase (%)	**3.0**	**3.0**	**–**
Benefit cost for year ended Dec. 31			
Discount rate (%)	**7.2**	**7.3**	**7.0**
Rate of compensation increase (%)	**3.2**	**3.3**	**–**
Expected rate of return on plan assets (%)	**7.1**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	**–**	**–**	**9.2–10.5[1]**
Dental care cost escalation (%)	**–**	**–**	**4.0**
Provincial health care premium escalation (%)	**–**	**–**	**6.0**

Year ended Dec. 31, 2008	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate (%)	7.2	7.3	7.1
Rate of compensation increase (%)	3.2	3.3	–
Benefit cost for year ended Dec. 31			
Discount rate (%)	5.5	5.5	5.7
Rate of compensation increase (%)	3.7	3.8	–
Expected rate of return on plan assets (%)	7.1	–	–
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation (%)	–	–	9.0–10.5[1]
Dental care cost escalation (%)	–	–	4.0
Provincial health care premium escalation (%)	–	–	2.5

1 Decreasing gradually to five per cent by 2018 for Canadian plans and by 2017–2020 for U.S. plans and remaining at that level thereafter.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan.

H. Sensitivity Analysis

The following changes would occur in the defined benefit and other health and dental benefit plans if there was a change of +/– one percentage point in the discount rate, trend rate, or expected rate of return on plan assets:

Canadian plans:

Year ended Dec. 31, 2009	Registered	Supplemental	Other
1% increase in the discount rate			
Impact on 2009 accrued benefit obligation	**(30)**	**(6)**	**(1)**
Impact on 2010 estimated expense	**(1)**	**(1)**	**–**
1% decrease in the discount rate			
Impact on 2009 accrued benefit obligation	**35**	**8**	**2**
Impact on 2010 estimated expense	**1**	**1**	**–**
1% increase in the trend rate			
Impact on 2009 accrued benefit obligation	**–**	**–**	**2**
Impact on 2010 estimated expense	**–**	**–**	**–**
1% decrease in the trend rate			
Impact on 2009 accrued benefit obligation	**–**	**–**	**(1)**

Impact on 2010 estimated expense	–	–	–
1% increase in the expected rate of return on plan assets			
Impact on 2010 estimated expense	**(3)**	–	–
1% decrease in the expected rate of return on plan assets			
Impact on 2010 estimated expense	**3**	–	–

U.S. plans:

Year ended Dec. 31, 2009	Pension	Other
1% increase in the discount rate		
Impact on 2009 accrued benefit obligation	**(2)**	**(1)**
Impact on 2010 estimated expense	–	–
1% decrease in the discount rate		
Impact on 2009 accrued benefit obligation	**3**	**1**
Impact on 2010 estimated expense	–	–
1% increase in the trend rate		
Impact on 2009 accrued benefit obligation	–	**2**
Impact on 2010 estimated expense	–	–
1% decrease in the trend rate		
Impact on 2009 accrued benefit obligation	–	**(1)**
Impact on 2010 estimated expense	–	–
1% increase in the expected rate of return on plan assets		
Impact on 2010 estimated expense	–	–
1% decrease in the expected rate of return on plan assets		
Impact on 2010 estimated expense	–	–

32. JOINT VENTURES

Joint ventures at Dec. 31, 2009 included the following:

Joint venture		Description
Sheerness joint venture	50%	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Canadian Utilities Limited
Meridian joint venture	50%	Cogeneration plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by TransAlta
Fort Saskatchewan joint venture	60%	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake joint venture	50%	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power joint venture	50%	Gas-fired plant in Australia operated by TransAlta
CE Generation LLC	50%	Geothermal and gas plants in the United States operated by CE Gen affiliates
Genesee 3	50%	Coal-fired plant in Alberta operated by Capital Power Corporation
Wailuku	50%	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company
Keephills 3	50%	Coal-fired plant under construction in Alberta. The plant is being developed jointly with Capital Power Corporation and will be operated by TransAlta
Taylor Hydro	50%	Hydro facility in Alberta operated by TransAlta
Soderglen	50%	Wind generation facilities in Alberta operated by TransAlta
Pingston	50%	Hydro facility in British Columbia operated by TransAlta

Summarized information on the results of operations, financial position and cash flows relating to the Corporation's pro-rata interests in its jointly controlled corporations was as follows:

	2009	2008	2007
Results of operations			
Revenues	**539**	619	609
Expenses	**(409)**	(494)	(454)
Non-controlling interests	**(34)**	(55)	(44)
Proportionate share of net earnings	**96**	70	111
Cash flows			
Cash flow from operations	**111**	273	112
Cash flow used in investing activities	**(168)**	(376)	(147)
Cash flow (used in) from financing activities	**(60)**	30	(93)
Proportionate share of decrease in cash and cash equivalents	**(117)**	(73)	(128)
Financial position			
Current assets	**147**	166	91
Long-term assets	**2,371**	2,144	1,924
Current liabilities	**(114)**	(202)	(144)
Long-term liabilities	**(356)**	(503)	(390)
Non-controlling interests	**(325)**	(351)	(373)
Proportionate share of net assets	**1,723**	1,254	1,108

33. SUBSEQUENT EVENTS

TransAlta has evaluated subsequent events through to Feb. 23, 2010, which represents the date the consolidated financial statements were issued. TransAlta has not evaluated any subsequent events after that date.

Summerview 2

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

Kent Hills Expansion

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

TRANSALTA CORPORATION

RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

DECEMBER 31, 2009

INDEPENDENT AUDITORS' REPORT ON RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

To the Board of Directors of TransAlta Corporation

On February 23, 2010, we reported on the consolidated balance sheets of TransAlta Corporation as at December 31, 2009 and 2008 and the consolidated statements of earnings and retained earnings, comprehensive income and cash flows for each of the years in the three year period ended December 31, 2009 (the "Consolidated Financial Statements") which are included in the Annual Report on Form 40-F.

In connection with our audits conducted in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) of the Consolidated Financial Statements, we also have audited the related supplemental note entitled "Reconciliation to United States Generally Accepted Accounting Principles" included in the Form 40-F. This supplemental note is the responsibility of the Corporation's management. Our responsibility is to express an opinion on this supplemental note based on our audit.

In our opinion, such supplemental note, when considered in relation to the Consolidated Financial Statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in the supplemental note entitled "Reconciliation to United States Generally Accepted Accounting Principles", the Corporation changed its method of accounting for business combinations and non-controlling interest by the adoption of the guidance originally issued by the Financial Accounting Standards Board (FASB) Statement No. 141(R), *Business Combinations* (codified in FASB Accounting Standards Codification (ASC) Topic 805, *Business Combinations),* and FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, an amendment of Accounting Research Bulletin (ARB) No. 51 (codified in FASB ASC Topic 810, *Consolidation)*, both effective January 1, 2009.

Ernst & Young LLP

Calgary, Canada
February 23, 2010
Chartered Accountants

RECONCILIATION TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

This financial information has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"), which, in most respects, conform to the United States Generally Accepted Accounting Principles ("U.S. GAAP"). This information does not include all of the disclosures included in TransAlta Corporation's annual consolidated financial statements. Accordingly, this information should be read in conjunction with the Corporation's most recent annual audited consolidated financial statements. All amounts herein are in millions of Canadian dollars unless otherwise noted.

The material differences to reconcile Canadian GAAP to U.S. GAAP are described below:

A. EARNINGS, EARNINGS PER SHARE ("EPS") AND COMPREHENSIVE INCOME INFORMATION

Year ended Dec. 31	*Reconciling items*	**2009**	2008	2007
Net earnings - Canadian GAAP		**181**	235	309
Net earnings attributable to non-controlling interests		**38**	61	48
Revenues, net of tax	*X*	**(21)**	-	-
Pension cost, net of tax	*V*	**(6)**	(6)	(5)
Start-up costs, net of tax	*III*	**5**	-	-
Share-based payment, net of tax	*VII*	**(1)**	1	-

Sale of minority interest in Kent Hills	*VIII*	**(1)**	-	-
Acquisition-related costs, net of tax	*IX*	**(26)**	-	-
Net earnings - U.S. GAAP		**169**	291	352
Net earnings attributable to non-controlling interests - U.S. GAAP		**38**	61	48
Net earnings attributable to TransAlta - U.S. GAAP		**131**	230	304
Weighted average number of common shares outstanding in the period		**201**	199	202
Net earnings attributable to TransAlta per share, basic and diluted - U.S. GAAP		**0.65**	1.16	1.50

Year ended Dec. 31	*Reconciling items*	**2009**	2008	2007
Net earnings - U.S. GAAP		**169**	291	352
Other comprehensive income (loss) - Canadian GAAP		**246**	306	(3)
Difference in cumulative translation adjustment between U.S. and Canadian GAAP		-	-	7
Employee future benefits	*V*	**(22)**	(18)	12
Cash flow hedges	*I*	**(12)**	7	-
Comprehensive income - U.S. GAAP		**381**	586	368
Comprehensive income attributable to non-controlling interests - U.S. GAAP		**38**	61	48
Comprehensive income attributable to TransAlta - U.S. GAAP		**343**	525	320

B. BALANCE SHEET INFORMATION

		2009		2008	
As at Dec. 31	*Reconciling items*	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP [(1)]	U.S. GAAP [(1)]
Assets					
Property, plant and equipment, net	*I*	**7,578**	**7,594**	6,034	6,024
Goodwill	*IX*	**434**	**409**	142	142
Net risk management assets (including current portion)	*X*	**245**	**216**	171	171
Other assets	*III*	**102**	**102**	39	34
Liabilities					
Long-term debt		**4,411**	**4,411**	2,564	2,566
Deferred credits and other liabilities	*V*	**136**	**254**	131	212
Net future or deferred income tax liabilities (including current portion)	*I, II, V, VII, IX, X*	**473**	**438**	359	331
Non-controlling interests	*VIII*	**478**	**-**	469	-
Equity					
Contributed surplus	*IV*	**-**	**133**	-	132
Retained earnings	*III, IV, V, VII, VIII*	**634**	**436**	688	540
Accumulated other comprehensive income	*I, V*	**126**	**69**	61	7
Non-controlling interests	*VIII*	**-**	**478**	-	469

[(1)] Certain of the comparative figures have been reclassified to conform with the current year's presentation. Such reclassification did not impact previously reported net earnings or retained earnings. Refer to Note 2 of the annual audited consolidated financial statements.

C. RECONCILING ITEMS

I. Cash Flow Hedges

Under Canadian GAAP, certain gains and losses on derivatives designated as cash flow hedges can be included in the carrying amount of the underlying hedged item. Under U.S. GAAP, these gains and losses must be reclassified to Other Comprehensive Income ("OCI"). In addition, amounts from cash flow hedges must be reclassified from OCI into net earnings in the same period during which the underlying hedged item affects net earnings.

II. Income Taxes

Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP.

Deferred income taxes under U.S. GAAP are as follows:

As at Dec. 31	**2009**	2008
Future income tax liabilities (net) under Canadian GAAP	**(473)**	(359)
Start-up costs	**-**	3
Pensions	**32**	23
Cash flow hedges	**(4)**	2
Embedded derivatives	**7**	-
Deferred income tax liabilities (net) under U.S. GAAP	**(438)**	(331)

Comprised of the following:

As at Dec. 31	**2009**	2008
Current deferred income tax assets	**17**	3
Long-term deferred income tax assets	**243**	271

Current deferred income tax liabilities	**(57)**	(9)
Long-term deferred income tax liabilities	**(641)**	(596)
	(438)	(331)

On Jan. 1, 2007, TransAlta adopted Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"), now contained in FASB Accounting Standards Codification ("ASC") Topic 740, *Income Taxes*. As of Dec. 31, 2009, the Corporation has $111 million of unrecognized tax benefits (2008 - $120 million). These unrecognized tax benefits, if recognized, would affect the effective tax rate. No material increase or decrease in unrecognized tax benefits is expected in the next 12 months.

The reconciliation between the opening and closing unrecognized tax benefits is provided below:

Accounting for Uncertainty in Income Taxes	
Balance, Dec. 31, 2007	135
Decrease as a result of tax positions taken during a prior period	(15)
Balance, Dec. 31, 2008	120
Increase as a result of tax positions taken during a prior period	3
Decrease as a result of settlements with taxation authorities	(12)
Balance, Dec. 31, 2009	**111**

The Corporation's income tax filings are subject to audit examination by taxation authorities. As at Dec. 31, 2009, the tax years that remain subject to examination in major jurisdictions are: 1997 – 2009 in Canada, 2006 – 2009 in the U.S., 2003 – 2008 in Mexico, and 1996-2009 in Australia.

The Corporation's accounting policy is to include interest and penalties as a component of income taxes. As at Dec. 31, 2009, the amount of interest and penalties included in deferred income tax liabilities is $5 million (2008 - $8 million).

III. Start-Up Costs

Starting in 2009, under Canadian GAAP start up costs are no longer deferred and amortized. Consequently, the adjustment for start-up costs that was previously recorded to reconcile Canadian GAAP to U.S. GAAP has been determined to be unnecessary.

IV. Contributed Surplus

In 1998, the Corporation transferred generation assets to one of its subsidiaries, TA Cogen. TA Power, an unrelated entity, concurrently subscribed to a minority interest in TA Cogen. The fair value paid by TA Cogen for the assets exceeded their historical carrying values. For Canadian GAAP, the Corporation recognized a portion of this difference, to the extent it was funded by TA Power's investment in TA Cogen, as a gain on disposition. TA Power held an option to resell its interest in TA Cogen to the Corporation in 2018, but in 2003, TA Power's option to resell these units was eliminated and the unamortized balance of the gain was recognized in income.

Under FASB Accounting Research Bulletin ("ARB") No. 51, *Consolidated Financial Statements,* now contained in FASB ASC Topic 810, *Consolidation,* the option initially held by TA Power to potentially resell TA Cogen units to the Corporation in 2018 causes the excess of the consideration paid by TA Power over the Corporation's historical carrying value in these assets to be characterized as contributed surplus.

V. Pension Plans

An additional difference between Accumulated Other Comprehensive Income ("AOCI") under Canadian and U.S. GAAP is related to the adoption of Financial Accounting Standards No. 158 ("SFAS 158"), *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, now contained in FASB ASC Topic 715, Compensation – Retirement Benefits. Under U.S. GAAP, gains and losses recognized on pension plans and post-retirement benefits are recorded to OCI but are charged to earnings as services are rendered under Canadian GAAP. Consequently, the pension benefit cost under U.S. GAAP is impacted by the amounts amortized through AOCI which does not affect the pension benefit cost under Canadian GAAP. The pension benefit cost is adjusted for this difference.

Pre-tax amounts recognized in AOCI are as follows:

Year ended Dec. 31	**2009**			2008		
	Pension benefits	**Other benefits**	**Total**	Pension benefits	Other benefits	Total
Net actuarial loss	**(80)**	**(11)**	**(91)**	(60)	(1)	(61)
Past service cost	**(2)**	**(2)**	**(4)**	(2)	(3)	(5)
Difference between Canadian and U.S. GAAP included in AOCI	**(82)**	**(13)**	**(95)**	(62)	(4)	(66)

Pre-tax amounts recorded in Other Comprehensive Income ("OCI") were as follows:

As at Dec. 31	**2009**		
	Pension benefits	**Other benefits**	**Total**
Amortization of net loss from AOCI to net income	**(1)**	**(1)**	**(2)**
Net actuarial loss	**24**	**12**	**36**

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $3 million and nil, respectively. The estimated net actuarial loss and prior service cost for the other defined benefit postretirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $1 million and nil, respectively.

The components of AOCI under U.S. GAAP for adjustments as disclosed in reconciling items I and V are as follows:

Year ended Dec. 31	**2009**	2008
Cumulative unrealized gains (losses) on translating self-sustaining foreign operations, net of hedges and tax	**(63)**	6
Cumulative unrealized gains (losses) on cash flow hedges, net of tax	**201**	48
Pensions, net of tax	**(69)**	(47)
Accumulated other comprehensive income	**69**	7

VI. Joint Ventures

In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the SEC, the Corporation, as a Foreign Private Issuer, has elected to account for incorporated joint ventures using the proportionate consolidation method. See disclosure of the amounts proportionately consolidated in Note 32 of the Corporation's 2009 annual audited consolidated financial statements.

VII. Share-Based Payment

Under U.S. GAAP, the Corporation is required to measure the cost of employee services received in exchange for an award of cash-settled instruments based on the current fair value of the award. The fair value of the award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the service period will be recognized as compensation expense over that period. FAS 123(R), now contained in FASB ASC Topic 718, *Compensation — Stock Compensation,* also requires that the adjusted fair value of these instruments be classified as a liability instrument rather than as an equity instrument. The difference in measurement had no impact on the financial information presented herein as it was immaterial.

VIII. Sale of Minority Interest

During the second quarter of 2009, the Corporation sold 17 per cent of its Kent Hills project to Natural Forces Technologies Inc. and recorded a pre-tax gain of $1 million in accordance with Canadian GAAP. FAS 160, *Noncontrolling Interests in Consolidated Financial Statements*, now contained in FASB ASC Topic 810, *Consolidation*, requires that any difference between the fair value of the consideration received and the amount by which the non-controlling interest is adjusted should be recognized in equity attributable to the parent. As at Dec. 31, 2009, $1 million of other income has been reclassified and included in retained earnings.

IX. Acquisition of Canadian Hydro Developers

On Oct. 23, 2009, TransAlta completed the acquisition and payment for 87 percent of the outstanding common shares of Canadian Hydro Developers. On Nov. 4, 2009, TransAlta acquired the remaining 13 percent of the issued and outstanding shares. The total cash consideration paid was $755 million. This acquisition resulted in acquired intangibles of $176 million which have a weighted average amortization period of 19 years and goodwill of $278 million. No amounts of goodwill were deductible for tax purposes. The results of Canadian Hydro Developers are included in the consolidated financial statements of the Corporation from the acquisition date of Oct. 23, 2009.

Under U.S. GAAP, FASB ASC Topic 805, *Business Combinations,* the acquisition method is applied where the identifiable assets acquired and liabilities assumed are measured at their acquisition-date fair value. Acquisition-related costs of $26 million, net of tax were expensed under U.S. GAAP rather than capitalized, as was done under Canadian GAAP.

Through the acquisition of Canadian Hydro Developers, TransAlta will have unparalleled operational and development expertise, a robust growth portfolio, and a strong balance sheet. By expanding the wind operations, TransAlta will be well positioned as a North American leader in renewable energy.

The details of the cash consideration are as follows:

Cost of the transaction	
Total shares acquired (millions)	143.8
Price per share	5.25
Total cash consideration	**755**

The following table summarizes the estimated fair values of assets acquired and liabilities assumed as of the acquisition date:

Assets:		
Current assets	**49**	
Property, plant, and equipment	**1,291**	
Intangible assets	**176**	
Development costs	**22**	
Goodwill	**278**	
Total assets acquired		1,816
Liabilities:		
Current liabilities	**54**	
Current risk management liabilities	**6**	
Long-term risk management liabilities	**34**	
Long-term debt	**931**	
Deferred income tax liabilities	**33**	
Asset retirement obligation	**3**	
Total liabilities assumed		1,061
Total purchase price		**755**

Although TransAlta does not anticipate material changes to this preliminary allocation, the values may change when the evaluation of fair value information is complete.

The following table reflects the operating results of Canadian Hydro Developers that have been included in the consolidated financial statements since the date of acquisition:

For the period ended Dec. 31, 2009	**Total**
Revenue	**29**
Net earnings	**–**

The following table reflects pro forma operating results for the Corporation, assuming the acquisition of Canadian Hydro Developers occurred as of the beginning of each of the periods presented:

Year ended Dec. 31	**2009**	2008
Revenue	**2,855**	3,190
Net earnings	**162**	261

X. Embedded Derivatives

Under U.S. GAAP, FASB ASC Topic 815, *Derivatives and Hedging,* an embedded foreign currency derivative instrument is required to be separated from its host contract when the currency in which the price of the related good or service that is acquired or delivered is not routinely denominated in international commerce and is not the functional currency of the parties to the contract. Under Canadian GAAP, the separation of the embedded derivative is not required since the currency of the embedded foreign currency derivative instrument is commonly used in contracts to purchase or sell non-financial items in the economic environment in which the transaction takes place. As a result of the difference in standards for recognizing embedded foreign currency derivatives, TransAlta was required to separately record an embedded

derivative under U.S. GAAP. The amount of the separated embedded foreign currency derivative instrument recognized is $29 million and the unrealized loss of $21 million, net of tax has been recognized in net earnings.

XI. Private Equities

TransAlta holds private equity funds in its Canadian pension plan that are entered into under ten year agreements at which time they are redeemed. These private equities seek to provide a return to investors with the following strategies: North Pole Capital Investments Limited Class A Series 1 is a multi-strategy hedge fund that seeks to inexpensively acquire volatility from multiple, uncorrelated sources in order to produce absolute returns for investors in all market conditions. Lumira Capital I Limited Partnership holds a mixture of public and private companies in the life sciences sector. Novacap II, L.P. operates a venture capital business specializing in the manufacturing sector and technology sector. Northleaf Global Private Equity Investors I seeks to build a diversified portfolio of investments in private equity funds managed by fund mangers with a focus on investments in venture capital and buyout funds, principally in North America and Western Europe.

D. CHANGES IN ACCOUNTING STANDARDS

I. Current Accounting Changes

1. Decreases in Ownership of a Subsidiary

On Dec. 31, 2009, the Corporation adopted ASU 2010-02, *Accounting and Reporting for Decreases in Ownership of a Subsidiary — a Scope Clarification*, now contained in FASB ASC Topic 810, *Consolidation*. This amendment clarifies scope and disclosure requirements for a decrease in ownership of a subsidiary when an entity ceases to have a controlling interest in the subsidiary. The implementation of this standard did not have an impact on this financial information.

2. Measuring Fair Value of Certain Alternative Investments

On Dec. 31, 2009, the Corporation adopted ASU 2009-12, *Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*. ASU 2009-12 amends FASB ASC Topic 820, *Fair Value Measurements and Disclosure*, to provide additional measurement guidance and disclosures on the fair value of certain alternative investments such as private equity. Disclosure required as a result of adopting this standard can be found in Note XI of this financial information.

3. Employers' Disclosure about Pensions and Other Postretirement Benefits

On Dec. 31, 2009, the Corporation adopted FASB Staff Position FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*, to provide increased disclosure on the assets of a defined benefit pension or other postretirement plan. FSP FAS 132(R)-1 is now contained in FASB ASC Topic 715, *Compensation — Retirement Benefits*. Disclosure that meets the requirement of this standard can be found in Note 31 of the Corporation's 2009 annual audited consolidated financial statements.

4. FASB Accounting Standards Codification ™

On Sept. 30, 2009, the Corporation adopted Accounting Standards Update ("ASU") No. 2009-01, *The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles*, previously issued as the Statement of Financial Accounting Standard No. 168. The Codification is approved as the single source of authoritative nongovernmental U.S. GAAP which does not change current U.S. GAAP, but is intended to simplify user access to all authoritative U.S. GAAP by providing all the authoritative literature related to a particular topic in one place. All existing accounting standard documents will be superseded and all other accounting literature not included in the Codification will be considered non-authoritative.

5. Measuring Liabilities at Fair Value

On Sept. 30, 2009, the Corporation adopted ASU 2009-05, *Measuring Liabilities at Fair Value*. ASU 2009-05 amends FASB ASC Topic 820, *Fair Value Measurements and Disclosure*, previously issued as FSP, FAS 157-f, *Measuring Liabilities at Fair Value*, for the fair value measurement of liabilities when a quoted price in an active market is not available. The implementation of this standard did not have an impact on this financial information.

6. Accounting for Own-Share Lending Arrangements

On July 1, 2009, the Corporation adopted Emerging Issues Task Force ("EITF") Issue No. 09-1, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance*, now contained in ASU 2009-15. The issue requires an entity to initially measure a share-lending arrangement at fair value and for it to be treated as an issuance cost, and to exclude the shares borrowed under the share-lending arrangement from basic and diluted EPS. ASU 2009-15 also requires the entity to record a loss in current earnings equal to the fair value of the shares outstanding less any recoveries if it becomes probable that the counterparty will default on the arrangement. The implementation of this standard did not have an impact on this financial information.

7. Subsequent Events

On June 30, 2009, the Corporation adopted FASB Statement No. 165, *Subsequent Events*, now contained in FASB ASC Topic 855, *Subsequent Events*, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued. Disclosure that meets the requirement of this standard can be found in Note 33 of the Corporation's 2009 annual audited consolidated financial statements.

8. Fair Value of Financial Instruments Disclosures

On June 30, 2009, the Corporation adopted FASB Staff Position FAS 107-1, Interim *Disclosures about Fair Value of Financial Instruments*, now contained in FASB ASC Topic 825, *Financial Instruments*, which requires disclosures about fair value of financial instruments for interim and annual reporting periods. As a result of adopting this standard, summarized financial information on financial instruments provided at annual reporting periods is additionally disclosed at interim reporting periods.

9. Disclosure on Determining Fair Value When Market Value Declines

On June 30, 2009, the Corporation adopted FASB Staff Position FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*, now contained in FASB ASC Topic 820 *, Fair Value Measurements and Disclosures*, which provides guidance for estimating the fair value when the volume of activity for the asset or liability has significantly decreased. Topic 820 requires disclosure of any change in the valuation technique used to evaluate fair value when the volume has significantly decreased such as moving from a market approach to an income approach or moving to a multiple valuation technique. Additional guidance is provided to identify when a transaction is a forced liquidation or distressed sale. The implementation of this standard did not have an impact on this financial information.

10. Recognition and Presentation of Other-Than-Temporary Impairments

On June 30, 2009, the Corporation adopted FASB Staff Position FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* , now contained in FASB ASC Topic 320, *Investments — Debt and Equity Securities*, which provides guidance on estimating fair value when the volume and level of transaction activity for an asset or liability has significantly decreased in relation to normal market activity for the asset or liability. The implementation of this standard did not have an impact on this financial information.

11. Business Combinations

On Jan. 1, 2009, the Corporation adopted FASB Statement No. 141(R), Business Combinations, now contained in FASB ASC Topic 805, *Business Combinations.* This standard results in significant changes with respect to accounting for business combinations in consolidated financial statements. Disclosure required as a result of adopting this standard can be found in Note IX of this financial information.

12. Non-controlling Interests

On Jan. 1, 2009, the Corporation adopted FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51*, in conjunction with the IASB standards and now contained FASB ASC Topic 810, *Consolidation*. Under Topic 810, changes in ownership percentages without loss of control are treated as equity transactions. Non-controlling interests are required to be reported under equity and the income attributable to the non-controlling interests is to be disclosed. Disclosure that meets the requirement of this standard can be found in the Earnings, Earnings per Share ("EPS") and Comprehensive Income Information and the Balance Sheet Information in this reconciliation.

13. Disclosures about Derivative Instruments and Hedging Activities

On Jan. 1, 2009, the Corporation adopted FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities* — an amendment of FASB Statement No. 133, now contained in FASB ASC Topic 815, *Derivatives and Hedging*. Topic 815 is intended to improve financial reporting about derivative instruments and hedging activities by requiring entities to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Topic 815 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. Disclosure that meets the requirement of this standard can be found in Notes 7 and 9 of the Corporation's 2009 annual audited consolidated financial statements.

14. Determination of the Useful Life of Intangible Assets

On Jan. 1, 2009, the Corporation adopted FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets*. FSP FAS 142-3, now contained in FASB ASC Topic 350, *Intangibles – Goodwill and Other*, amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142. The intent of FSP FAS 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS 141(R) and other applicable accounting literature. The implementation of this standard did not have an impact on this financial information.

15. Issuer's Measurement of Debt with a Third-Party Credit Enhancement

On Jan. 1, 2009, the Corporation adopted EITF Issue No. 08-5, *Issuer's Measurement of Debt with a Third-Party Credit Enhancement,* now contained in FASB ASC Topic 820, *Fair Value Measurements and Disclosures*. This issue addresses that a separable third-party enhancement, such as a financial guarantee, should not be included in the fair value measurement of the liability. The implementation of this issue did not have an impact on this financial information.

II. Future Accounting Changes

1. Variable Interest Entities

In December 2009, the FASB issued ASU No. 2009-17, *Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities,* which is a result of FAS 167 issued in June 2009 and is now contained in FASB ASC Topic 810, *Consolidations*. Statement 167 is a revision to FASB Interpretation No. 46(R), *Consolidation of Variable Interest Entities* and it provides guidance on how to determine when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. This standard will be effective for the Corporation on Jan. 1, 2010. The Corporation is currently assessing the impact of adopting this standard on this financial information.

2. Transfers of Financial Assets

In December 2009, the FASB issued ASU No. 2009-16, *Accounting for Transfers of Financial Assets*, which is a result of FAS 166 issued in June 2009 and is now contained in FASB ASC Topic 860, *Transfers and Servicing.* Statement 166 is a revision to Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* and will require more disclosure on transfers of financial assets, including securitization transactions and continued exposure to the risks related to transferred financial assets. It also eliminates the concept of a "qualifying special-purpose entity," and provides requirements for derecognizing financial assets. This standard will be effective for the Corporation on Jan. 1, 2010. The Corporation is currently assessing the impact of adopting this standard on this financial information.

Exhibit 23.1



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CONSENT OF INDEPENDENT AUDITORS

We consent to the use of our reports dated February 23, 2010 with respect to the consolidated financial statements of TransAlta Corporation (the "Corporation") as at December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009, and internal control over financial reporting as of December 31, 2009 of TransAlta Corporation, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) for 2009.

We also consent to the use of our audit report dated February 23, 2010 to the Board of Directors of the Corporation with respect to the Reconciliation to United States Generally Accepted Accounting Principles as at December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) for 2009.

We also consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-72454 and No. 333-101470) pertaining to TransAlta Corporation's Share Option Plan

(2) Registration Statement (Form F-10 No. 333-155243 and No. 333-162418) pertaining to the registration of Debt and Equity Securities of TransAlta Corporation

of our reports dated February 23, 2010, with respect to the consolidated financial statements of TransAlta Corporation as at December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009, internal control over financial reporting as of December 31, 2009 of TransAlta Corporation and the Reconciliation to United States Generally Accepted Accounting Principles as of December 31, 2009 and 2008 and for each of the years in the three year period ended December 31, 2009, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) of TransAlta Corporation for the year ended December 31, 2009.

signed "Ernst & Young LLP"

Calgary, Alberta
February 23, 2010

Chartered Accountants

Exhibit 31.1

Certifications

I, Stephen G. Snyder, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

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

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

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

February 24, 2010

/s/ Stephen G. Snyder
Stephen G. Snyder
President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Brian Burden, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

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

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

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

February 24, 2010

/s/ Brian Burden
Brian Burden
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Stephen G. Snyder, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Stephen G. Snyder
Stephen G. Snyder
President and Chief Executive Officer

Dated: February 24, 2010.

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian Burden, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Brian Burden
Brian Burden
Chief Financial Officer

Dated: February 24, 2010.

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.