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Toronto, Ontario M5J 2Z4 CANADA
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On January 1, 2012, Macleod Dixon joined Norton Rose OR to create Norton Rose Canada.

October 29, 2012

Sent By Courier

Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700
2300 Yonge Street
Toronto, ON M4P 1E4

Your reference	Direct line +1 (416) 216-2311
Our reference 01006099-0402	Email richard.king@nortonrose.com

Dear Ms. Walli:

TransAlta Generation Partnership ("TAGP")
Distribution Licence Application – Threshold Question

We are counsel to TAGP. This letter is further to our letter to the Board of June 22, 2012 which included:

- a Notice of Proposal filed pursuant to section 81 of the *Ontario Energy Board Act, 1998* (the "OEB Act") (disposed of by the Board under docket no. EB-2012-0298); and
- clarification as to whether an electricity distribution licence is required in connection with TAGP's plans to construct electricity distribution facilities from its Sarnia Regional Cogeneration Plant ("SRCP") to supply potential new and existing loads at a site owned by LANXESS (formerly owned by Bayer) immediately north of, and contiguous with, the SRCP site.

After discussions with Board staff, TransAlta is submitting the attached distribution licence application (with application fee) in connection with the second bullet noted above. The circumstances related to the supply of power from the SRCP are set out below, and are somewhat unique. **It is our view, for reasons set out below, that an electricity distribution licence is not required. TAGP is therefore requesting that the Board determine, as a threshold issue, whether a distribution licence is required in order to supply power to the existing load at the LANXESS site, and potential new loads (located either on the LANXESS site or the SRCP site).**

The SRCP was one of the "early mover" generation facilities built in Ontario in anticipation of the move to a fully competitive wholesale and retail electricity market. The SRCP came into service in 2003 on a site in Sarnia owned by Dow Chemical Canada Inc. ("Dow Chemical"). The SRCP consisted of integrating TAGP's newly constructed generation facilities with the existing generation purchased by TAGP that had been owned and operated by Dow Chemical for its industrial purposes. In addition to the existing generation at Dow, TAGP also purchased existing generation at the LANXESS site immediately to the north of the Dow Chemical site. Whereas the existing generation at the Dow Chemical site was integrated with the newly constructed generation facilities (i.e., they were electrically connected), there was no electrical connection to the generation on the LANXESS site. As part of the SRCP project, TAGP supplied bulk steam and power to Dow Chemical, LANXESS, Suncor and NOVA pursuant to long-term contracts, with the remainder of generation sold into the Ontario power market (via a connection from the SRCP to the transmission grid).

DOCSTOR: 2453131\4

Dow Chemical permanently closed its Sarnia operations in 2009, and sold the site to TAGP. Schedule A to this letter shows a simplified drawing of the TAGP and LANXESS properties today. TAGP continues to own the older, existing generation on both the former Dow Chemical site and the LANXESS site, and continues to have a contractual commitment to supply steam and electricity to LANXESS. Rather than refurbish the older generation on the LANXESS site, TAGP has determined that it is more efficient to supply electricity via a new distribution voltage connection from the SRCP (see Schedule B for a simplified drawing). In addition, TAGP has an opportunity to supply additional new loads (i.e., corporate entities unrelated to LANXESS, TransAlta or Dow Chemical) which may locate on either the LANXESS site or the SRCP site. In the former case, please see Schedule C to this letter for a simplified electrical configuration. In the latter case, please see Schedule D to this letter for a simplified electrical configuration.

The ability to supply LANXESS and potential new loads via a distribution connection necessitated the filing of the section 81 Notice (construction of distribution facilities by a generator), and also raises the question of whether a distribution licence is required under section 57 of the OEB Act. It is this latter issue that TAGP would like the Board to determine as a threshold issue in this licence application.

<u>Distribution Licence Requirement</u>

Under section 57(a) of the OEB Act, a licence is required in order to "own or operate a distribution system". The term "distribution system" is defined to mean a "system for distributing electricity, and includes any structures, equipment or other things used for that purpose". Section 4.0.1 of Ontario Regulation 161/99 provides a number of exemptions from having to obtain an electricity distribution licence, including the following:

> 4.0.1 (1) Clause 57(a) ... of the Act do not apply to a distributor who distributes electricity for a price no greater than that required to recover all reasonable costs,
>
> (a) with respect to a distribution system owned or operated by the distributor that is entirely located on land on which one or more of the following types of building or facilities is also located: ...
>
> 3. An industrial, commercial or office building.
>
> ...
>
> (b) with respect to a distribution system owned or operated by the distributor that is entirely located on land owned or leased by the distributor; ...

TAGP will not charge LANXESS or any new load for the distribution of electricity. Consequently, the first part of subsection 4.0.1(1) of Ont. Reg. 161/99 is satisfied. The question then is whether the exemption in clause 4.0.1(1)(a)(3) or paragraph 4.0.1(1)(b) applies. More specifically, TAGP is asking the Board to determine as a threshold issue, whether TAGP requires a distribution licence in order to:

- supply electricity to LANXESS via new electricity distribution facilities connected to the SRCP;
- supply electricity to any new load located on either the LANXESS site (as per Schedule C) or the SRCP site (as per Schedule D).

TAGP's submissions on these questions are as follows:

First, TAGP submits that the exemption provision in Ont. Reg. 161/99 is not sufficiently precise to cover the many different scenarios that could arise as a result of proposals to construct new distribution facilities. Consequently, the Board will be required to interpret subsection 4.0.1(1) of Ont. Reg. 161/99 and make determinations as to whether a licence is required by considering the wording and intent of the exemption provision, as well as the Board's statutory objectives and the Board's licensing powers within the context of the

OEB Act. To that end, there is no compelling reason to require TAGP to hold a distribution licence in order to supply LANXESS or a new load. As noted, TAGP will not be seeking to charge either LANXESS or the new load for distribution. TAGP will not be looking to expand the distribution facilities beyond the TAGP and LANXESS properties. The impetus for the distribution facilities is to meet a contractual commitment to supply LANXESS in a way that is more economically and environmentally efficient than refurbishing old generation on the LANXESS site that TAGP owns. It would allow for increased expansion at the LANXESS site (through increased LANXESS load or the addition of a new business on vacant land at the LANXESS site without having to expand LANXESS' transformer connected to the Hydro One Networks Inc. system). It would also allow TAGP to "replace" the load that was lost when Dow Chemical closed its Sarnia operations in 2009. All of this, TAGP submits, furthers the first two statutory objectives (electricity) of the OEB, namely: (a) to protect the interests of consumers (i.e., LANXESS and new load) with respect to the pricing, adequacy, reliability and quality of electricity service; and (b) to promote economic and cost efficiency in the generation, transmission and distribution of electricity. Supplying LANXESS and new load via distribution facilities connected to the SRCP would provide for a reliable, cost-effective and economically efficient means of securing electricity for these consumers. It is certainly more efficient, cost-effective and environmentally sounder than increasing the output at older, TAGP-owned generation. There would not need to be any new public utility connection assets built with the costs borne by LANXESS, the new loads or other ratepayers. Under any of the electrical configurations shown in Schedules B, C or D, the LANXESS load and new loads would continue to be supplied in the event that the SRCP went off-line.

With respect to the first exemption specifically (i.e., clause 4.0.1(1)(a)(3)), TAGP is of the view that no distribution licence is required because the distribution facilities would be located on land on which only industrial buildings are located. There is no requirement in subsection 4.0.1 that the land be a single parcel or that the buildings be on land owned by a single (or related) entities.

With respect to the second exemption (i.e., paragraph 4.0.1(1)(b)), TAGP submits that the wording of paragraph 4.0.1(1)(b) merely highlights the fact that the Board must determine the requirement for a distribution licence based on the facts of each particular case. If the provision is read literally, TAGP could simply lease land on the LANXESS site underlying the new distribution facilities and avail itself of the exemption. By doing so, TAGP could claim that the new distribution facilities are located entirely on land owned or leased by TAGP and therefore no distribution licence is required. This cannot be the intent of that provision. TAGP submits that it should not have to lease these lands in order to avail itself of the exemption from having to obtain a distribution licence.

Finally, none of the rationale behind the requirement to hold a distribution licence are relevant in the context of TAGP supplying LANXESS and any new load (regardless of whether located on TAGP's or LANXESS' property). Licensed distributors are, by virtue of being licensed, bound to a number of legal obligations: for example, they must be the default supplier of electricity, they must register with the Independent Electricity System Operator, they must keep books and record used for electricity distribution separate from books and records used for any other activities in order to permit easy auditing of their monopoly and non-monopoly activities, they cannot construct generation without Board approval, and cannot engage in any business other than electricity distribution except through an affiliate. These are all sensible legal requirements for typical local distribution companies that provide a public service to a diverse group of end-use customers and charge for doing so. This is not the case with TAGP, which would supply sophisticated industrial end-users. Moreover, TAGP is not seeking to provide this distribution service on a for-profit basis, and would not be at risk of abusing any market power in the absence of being subject to the Board's full regulatory regime applicable to distributors. Simply put, the purpose of the Board's licensing power in the context of electricity distributors in Ontario is not relevant to the situation being contemplated by TAGP in this application. It is not unlike the situation that existed at the SRCP for years (prior to Dow Chemicals' closure of operations), wherein TAGP supplied power to Dow via distribution voltage facilities without a Board licence.

For all of these reasons, TAGP submits that a distribution licence should not be required in order for TAGP to supply electricity to LANXESS or any new load at the LANXESS or TAGP site. At the outset of the processing of this application, TAGP is requesting that the Board determine, as a threshold issue, whether a distribution licence is required.

Should you have any questions, please contact me.

Yours very truly,

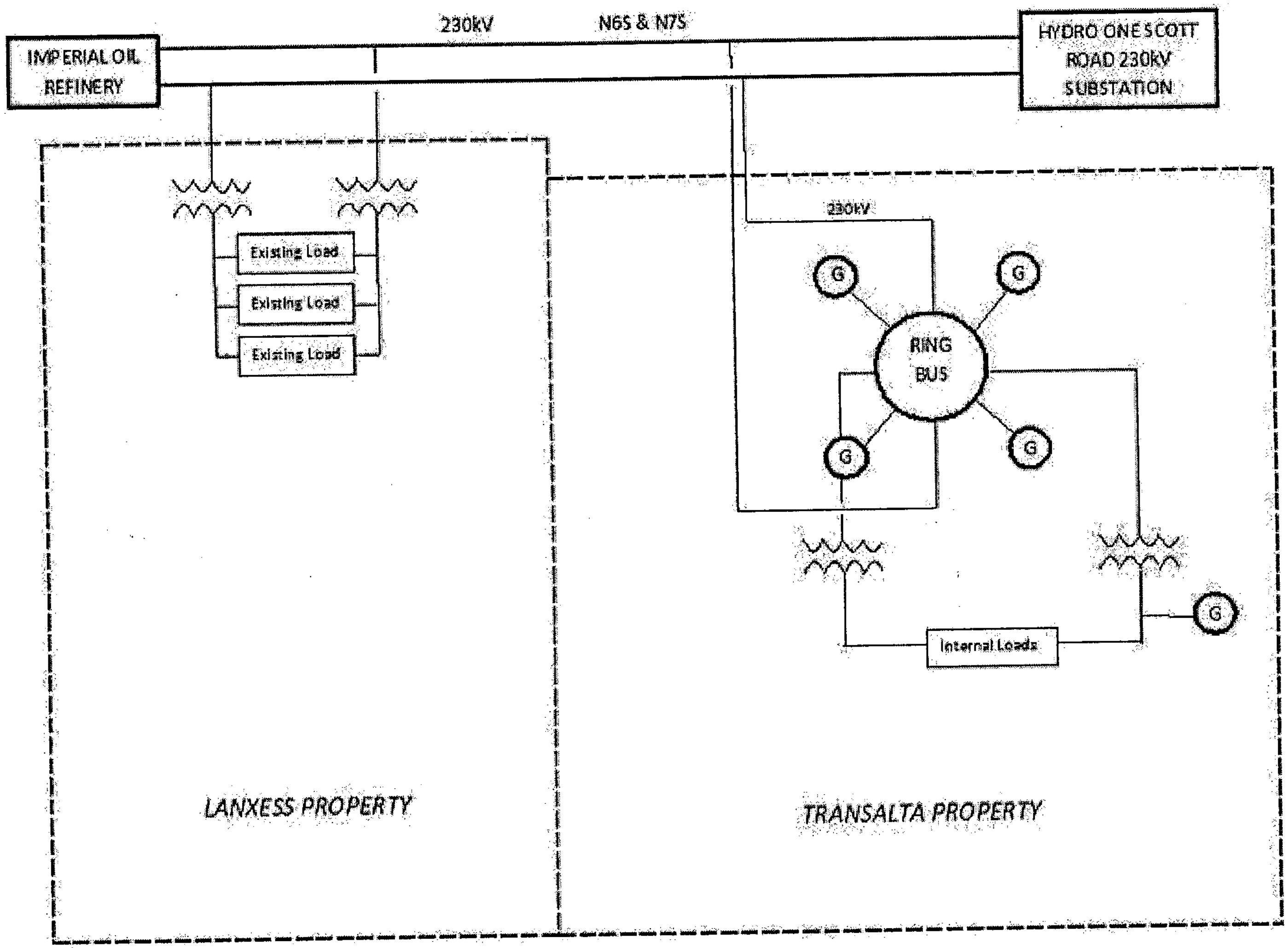
Richard King

RK/mnm

Enclosure(s)

Copy to: P. Smith (TransAlta)
A. Pye (OEB)

Schedule A



230kV
N6S & N7S
IMPERIAL OIL REFINERY
HYDRO ONE SCOTT ROAD 230kV SUBSTATION
Existing Load
Existing Load
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230kV
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Internal Loads
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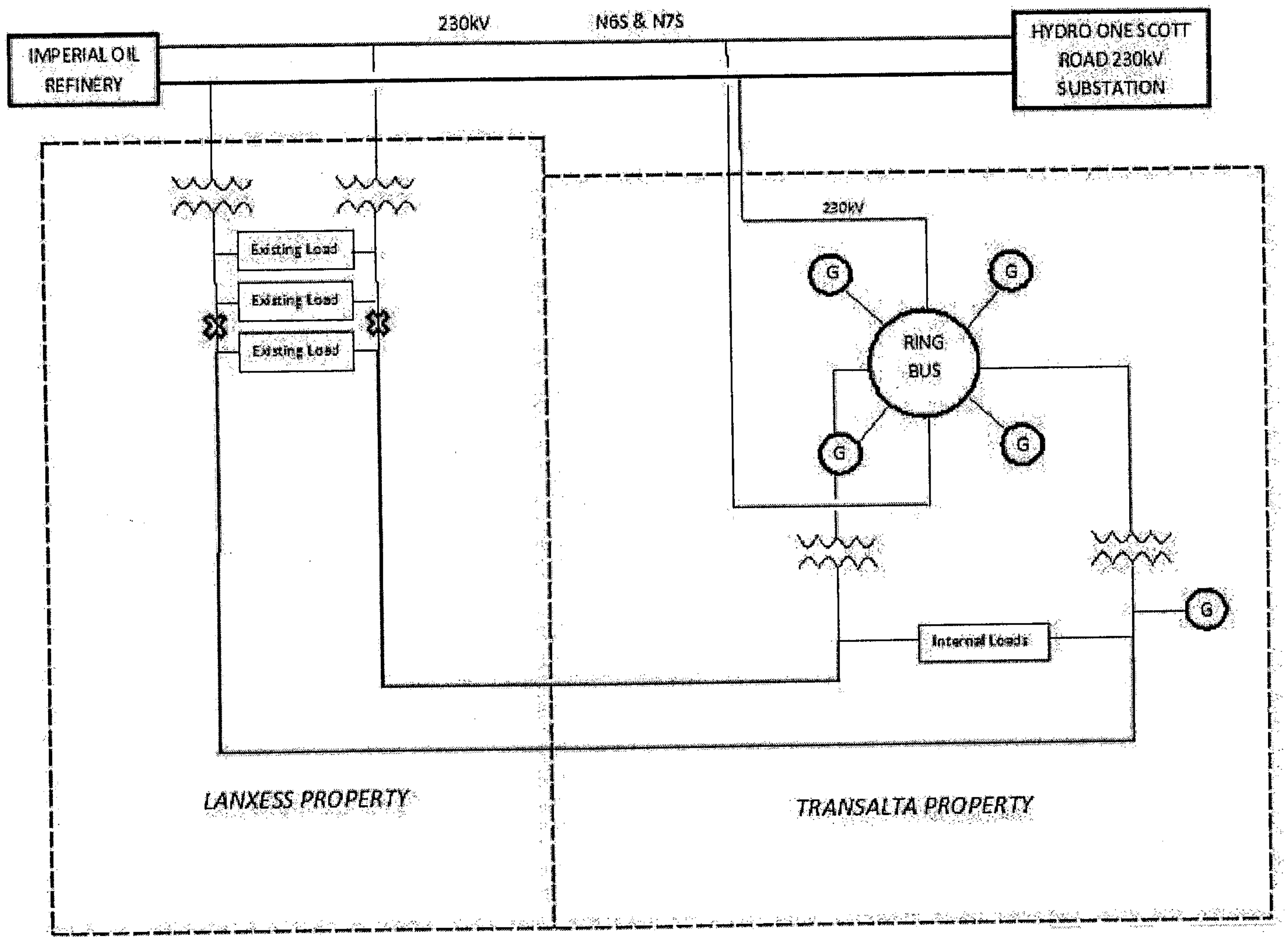
LANXESS PROPERTY
TRANSALTA PROPERTY

Schedule B


230kV
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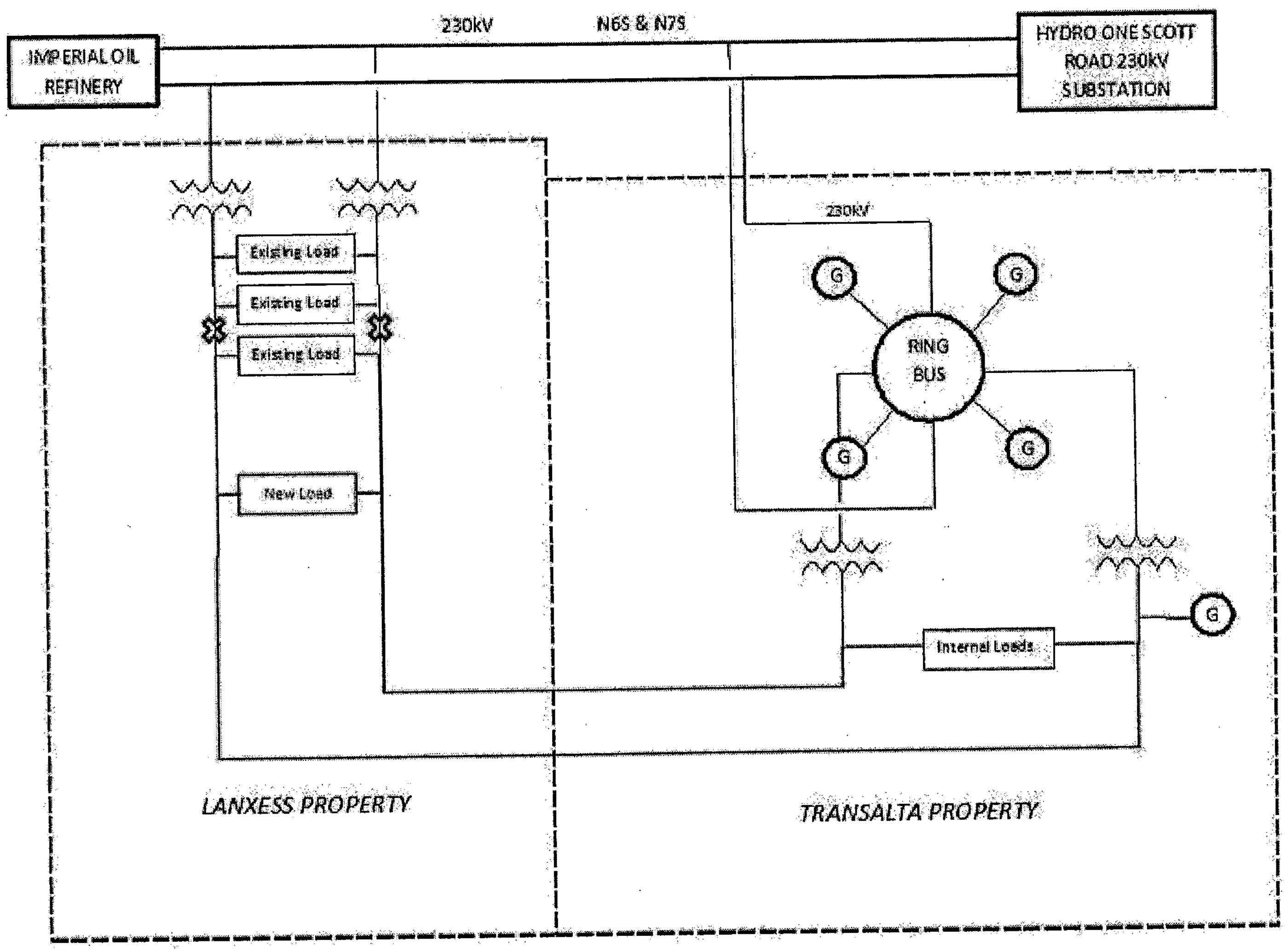
Internal Loads
LANXESS PROPERTY
TRANSALTA PROPERTY

Schedule C



230kV
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230kV
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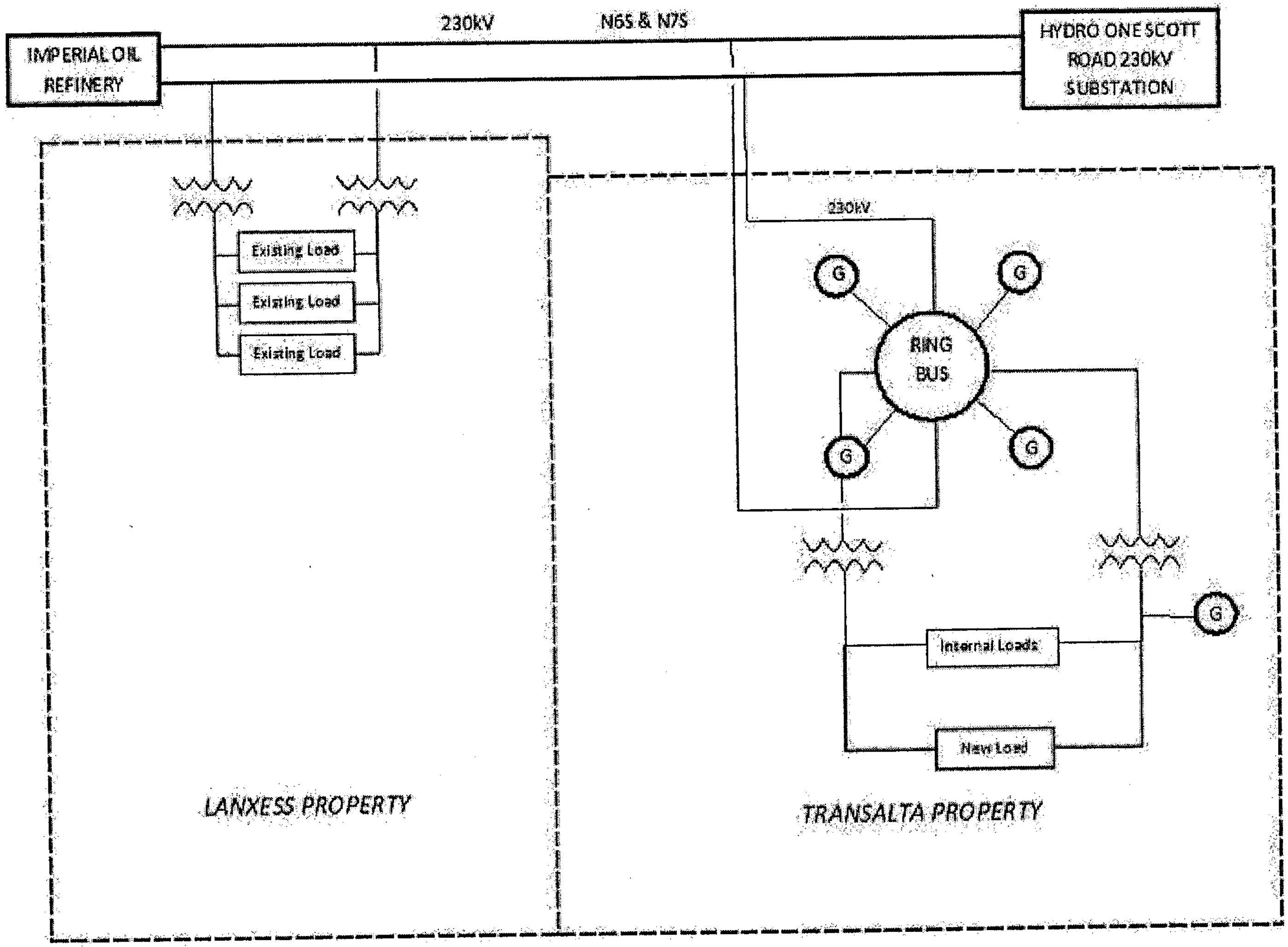
LANXESS PROPERTY
TRANSALTA PROPERTY

Schedule D



230kV
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Internal Loads
New Load
LANXESS PROPERTY
TRANSALTA PROPERTY

Ontario

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Application for Electricity Distribution Licence

Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4
Telephone: 1-888-632-6273
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
2300 rue Yonge
C.P. 2319
Toronto, ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656

Application Instructions

1. Purpose of this form

The purpose of this form is to collect information to determine whether the Applicant will be granted a licence to distribute electricity.

2. Structure of the Application Form

This form contains the following sections:

A General Information;
B Distribution Facilities Information;
C Supporting Information
D Notice and Consent and
E Acknowledgement

Note: The information in section C16 shall be kept confidential, with the exception of names and positions held of key individuals. All other information filed as part of this application will be considered public. Where the applicant objects to public disclosure of the information, the applicant must follow the Ontario Energy Board's approved Guidelines for Treatment of Filing made in Confidence, effective March19, 2001.

3. Completion Instructions

PRINT CLEARLY or TYPE all information in BLACK. Please send two copies of the completed form and all attachments to:

Board Secretary
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319, 26th Floor
Toronto, ON M4P 1E4

4. Licence Fees:

A non-refundable application fee is required to process your application. Please enclose a cheque or money order made payable to the **ONTARIO ENERGY BOARD**.

Note: If a licence is issued, the Licensee will be required to pay an annual fee of $800.00.

5. Important Information:

As a licenced Electricity Distributor, the licencee may be subject to additional obligations as required by the Independent Electricity System Operator (IESO) and as established under section 70 or section 78 of the *Ontario Energy Board Act, 1998*.

REMARQUE:
Ce document est disponible en français.

OEB App05A - July/05

Ontario Energy Board
Commission de l'Énergie de l'Ontario
Application for Electricity Distribution Licence

Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4
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Commission de l'Énergie de l'Ontario
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C.P. 2319
Toronto, ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656

For Office Use Only	
Application Number	
Date Received	

A. General information

1. Type of Application

New licence	☒
Renewal	☐
Amendment to an existing Licence	☐

2. Ownership/Operation

Please indicate whether the Application is for:

☒ Ownership and Operation of a distribution system

☐ Ownership of a distribution system only. Please provide the name and licence no., if any, of the operator of the distribution system?

☐ Operation of a distribution system only. Please provide the name and licence no., if any, of the owner of the distribution system?

3. Applicant

Please provide the following information about the Applicant:			
Full Legal Name of Applicant TransAlta Generation Partnership		Ontario Corporation Number, Canadian Corporation Number or Business Registration Number AB Registration No. PT14399588	Date of Formation or Incorporation Oct. 1, 2008
Business Address: 110- 12 Avenue SW			
City Calgary	Province Alberta	Country Canada	Postal/Zip Code T2R 0G7
Phone Number 403-267-7110	FAX Number 403-267-2575	E-Mail Address (if applicable) regulatory_legal@transalta.com	

4. Primary Contact for this Application

Please provide the following information about the Primary Contact for this Application:				
Mr. ☒ Mrs. ☐ Miss ☐ Ms. ☐ Other: ________	Last Name: Smith		Full First Name: Peter	Initial: R.
	Position Held: Director, Commercial Management East			
Contact Address (if R.R., give Lot, Concession No. and Township) 1741 River Road Box 3040				
City Sarnia	Province Ontario	Country Canada	Postal/Zip Code N7T 8H1	
Phone Number 519-464-5975	FAX Number 519-464-5832	E-mail Address (if applicable) peter_smith@transalta.com		

5. Service Area

Please indicate the location (name of municipality or unorganized territory) of the Applicant's distribution facilities and provide a description of the extent (size, length, coverage) of the distribution facilities involved in this Application. This description will be used for the purpose of stating a service area in which the licensee would be authorized to distribute electricity:

See Appendix "A" to licence application

6. Facilities Use

Please indicate whether the distribution facilities are for exclusive use by the Applicant.

Yes ☒ No ☐

B. Distribution Facilities Information

7. Facilities Type

Please indicate whether the Applicant's distribution facilities are:

☒ New assets to be constructed? Proposed In-service date: 2014 - 2015

If Applicant is to be the owner, please attach a statement explaining the financing arrangements.
See Appendix "A" to licence application

☐ Existing assets presently owned and/or operated by the Applicant?

☐ Existing assets not presently owned and/or operated by the Applicant (ie to be purchased)?

If Applicant is to be the owner please indicate:

a) from whom assets will be purchased:

b) when application for sale has/will be filed with the Board?

☐ Other (please describe):

8. Facilities Purpose

Please indicate the intended purpose(s) of the Applicant's distribution facilities:

- ☐ To provide a connection between a generator and a transmission/distribution system.
- ☐ To provide a connection between a transmission/distribution system and a load customer or customers.
- ☒ To provide a connection between a generator and a load customer or customers.
- ☐ To provide distribution services to the general public.
- ☐ Other (please describe):

9. Description of Facilities

Please describe the Applicant's distribution facilities indicating operating voltage(s) (kV), length of distribution line (km), number of substations and approximate total supply capacity (MW):

See Appendix "A" to licence application

10. Location of Facilities

Please indicate whether the distribution facilities will be located on, over or under public streets or highways.

Yes ☐ No ☒

C. Supporting Information Organizational Information

11. Business Classification

Sole Proprietor	☐
Partnership	☐
Corporation	☒
Other	☐

12. Affiliates of the Applicant

a) Please provide the following information for all Affiliates of the Applicant (attach a copy of 12(a) for each affiliate).

Full Legal Name of Affiliate Company: See Appendix "A" to licence application

Business Address:

City	Province	Country	Postal/Zip Code

Tel. Number	FAX Number	E-Mail Address (if applicable)

Description of Business Activities:

b) Please attach a Corporate organization chart describing the relationships between the Applicant and its Affiliates and, if applicable, the respective ownership percentages by the Applicant in each Affiliate. See Appendix "A" to licence application.

13. Energy Sector Activities

Has the Applicant or an Affiliate undertaken any energy sector activities in Ontario or any other jurisdiction? If yes, please provide the following information for each:	Yes ☒ No ☐
Full Legal Name of Company:	Licence/Registration Number:
Jurisdiction:	Type of Business Activity (e.g. Generation, Transmission, Distribution):

See Appendix "A" to licence application

Technical Capability and Experience Information

14. Business Activities

Please provide a description of the Applicant's business activities:
See Appendix "A" to licence application

15. Technical Ability

a) Please describe the applicant's technical ability to carry out the activities applied for including the Applicant's specific experience in Ontario and in other jurisdictions.
See Appendix "A" to licence application

b) If the Applicant intends to utilize the capability of others by contracting distribution activities, please indicate below which activities and to whom they will be contracted:

☐ Design	Contracted to:
☐ Construction	Contracted to:
☐ Inspection & Maintenance	Contracted to:
☐ Operation	Contracted to:
☐ Customer Connection	Contracted to:
☐ Standard Supply Service	Contracted to:
☐ Metering & Metering Services	Contracted to:
☐ Settlement & Billing	Contracted to:
☐ Other (describe):	Contracted to:

See Appendix "A" to licence application

16. Information About Each Key Individual

Mr. ☐ Mrs.☐ Miss ☐ Ms. ☐ Other: ________	Last Name:	Full First Name:	Initial:
	Position Held:		

Please explain the person's experience in the electrical distribution business and in the energy field in general.

Information about each key individual is provided in Appendix "A" of licence application

a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.* Yes ☐ No ☐

If yes, provide business names and licence number(s) and describe the individuals specific related experience.

b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation? Yes ☐ No ☐

If yes, identify the business name, the legislation, licence number(s), date of the licencing or registration and the individual's specific related experience.

c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled? Yes ☐ No ☐

If yes, please provide company name and describe the situation, including the jurisdiction and type of licence.

Note:
Attach a copy of Item 16 for each Key Individual: Officer and Director, Partner or sole Proprietor.

Financial Information

17. Financial Statements

Please attach financial statements of the Applicant for each of the past two fiscal years. This may include audited financial statements, annual reports, prospectuses or other such information. Annual Reports for 2011/2010 are at Appendix "B" of licence application

Other Information

18. Delivery

	Yes	No
Please indicate whether the Applicant's distribution facilities are to be used to deliver electricity to one or more parties other than the Applicant. If yes, please provide the following information:	☒	☐
a) if the purpose of the Applicant's distribution facilities is to provide distribution services to specific generators or load customers rather than the general public (see question #8) please indicate the names of these participants: For answers 18(a) - 18(d), please see Appendix "A" of licence application		
b) a summary of the business plans relating to the Applicant's proposed distribution business for the next five years. This should include the following: – a forecast of annual growth in terms of factors such as the amount of electricity distributed (MW and/or MWH), number of customers served, amount of distribution facilities (lines and/or stations), etc. – annual pro forma financial statements including forecasts of costs, revenues and project financing indicating the underlying assumptions on which the forecasts are based.		
c) estimates of net annual cash flows for subsequent periods to demonstrate financial feasibility and security.		
d) indication of the Applicant's plans to seek Ontario Energy Board approval for electricity distribution rates.		

19. Proposed Business Transactions

Please provide a brief summary of the expected impact of the proposed business transactions on the Ontario electricity market under the following headings:

a) Facilitate competition and enhance access to transmission/distribution services:

For answers 19(a) - 19(c), please see Appendix "A" of licence application

b) Improve reliability and quality of supply:

c) Promote economic and energy efficiency:

20. Electricity Sector Activities

Please indicate whether the Applicant intends to be involved with electricity sector activities in the Ontario market other than distribution and provision of Standard Supply Service?

	Yes	No	
Buy or Sell (Wholesale) electricity	☐	☐	
Transmit electricity	☐	☐	
Retail electricity	☐	☐	
Generate electricity	☒	☐	TAGP already a generator. See Item #14 in Appendix "A" of licence application

If yes to any of the above:

a) If affiliates have not yet been established, please indicate when this is planned: ______________

b) Has the Applicant or an affiliate applied for Ontario Energy Board Licences? If no, when planned?	Yes ☒ No ☐ See Item #12(a) in Appendix "A" of licence application

D. Notice and Consent for Ontario Board to Collect Additional Information

AS REQUIRED BY THE FREEDOM OF INFORMATION AND PROTECTION OF INDIVIDUAL PRIVACY ACT

In order to complete or verify the information provided on this form, it may be necessary for the Ontario Energy Board to collect additional information from some or all of the following sources: federal, provincial/state and municipal governments; licensing bodies; banks; professional and industry associations; and former and current employers. **Only information relevant to your application will be collected.**

The public official who can answer questions about the collection of information is:

Board Secretary
Ontario Energy Board
2300 Yonge Street, P.O. Box 2319
Toronto, Ontario M4P 1E4

Note: The issuance of an electricity distribution licence does not guarantee accreditation by the IESO, or connection to a transmission or distribution system.

NOTE: This application must be signed by the proprietor or by at least one partner, officer or director of the organization.

WARNING: It is an offence to knowingly provide false information on this application.

I/We consent to the collection of this information as authorized under the *Ontario Energy Board Act, 1998.* — Yes ☒

I/We understand that this information will be used to determine whether I am/we are and remain qualified for the licence for which I am/we are applying. — Yes ☒

Print Name and Title	Signature of Applicant(s)	Date Signed
PETER R. SMITH DIRECTOR, COMMERCIAL MANAGEMENT EAST	Peter R Smith	OCT 19, 2012

E. Acknowledgement of Market Rules, Codes and Conditions

NOTE: This acknowledgement must be signed by the proprietor or by at least one partner, officer or director of the organization.

I understand and acknowledge that, as a licenced electricity distributor, I will be required, unless otherwise exempted:

- To provide non-discriminatory access to all persons wishing to connect to the distribution system.
- To comply with all licence conditions including the provisions of:
  - Affiliate Relationships Code for Electricity Distributors and Transmitters
  - Distribution System Code
  - Retail Settlement Code
  - Standard Supply Service Code
  - Retail Metering Code
  - Market Rules made under section 32 of the *Electricity Act, 1998*.

Print Name and Title	Signature of Applicant(s)	Date Signed
PETER R. SMITH DIRECTOR, COMMERCIAL MANAGEMENT EAST	Peter R Smith	OCT 19, 2012

APPENDIX “A” TO LICENCE APPLICATION

APPENDIX "A" OF LICENCE APPLICATION

<u>Item #5 – Service Area:</u> Please indicate the location (name of municipality or unorganized territory) of the Applicant's distribution facilities and provide a description of the extent (size, length, coverage) of the distribution facilities involved in this Application. This description will be used for the purpose of stating a service area in which the licensee would be authorized to distribute electricity:

TransAlta Generation Partnership (TAGP) will construct, own and operate the proposed electricity distribution facilities from its Sarnia Regional Cogeneration Plant (SRCP), located at 1475 Vidal Street South in the municipality of Sarnia, to supply new and existing load at a site owned by LANXESS (formerly owned by Bayer) immediately north of, and contiguous with, the SRCP site located at 1265 Vidal Street South, Sarnia. The facilities may also supply potential new load on the SRCP site.

The proposed distribution facilities will consist of approximately 2km of 13.8kV line (some of which may be buried). These details may vary as the design is finalized.

Please see the attached letter and Schedules for additional details on the proposed facility.

<u>Item #7 – Facilities:</u> If Applicant is to be the owner, please attach a statement explaining the financing arrangements.

TAGP is still in the planning stages of this project and we have not finalized any financing arrangements at this time. Note that TAGP does currently have a contractual arrangement with LANXESS and will not be discussing financing or terms with other parties until TAGP is assured it can move forward with construction.

<u>Item #9 – Description of Facilities:</u> Please describe the Applicant's distribution facilities indicating operating voltage(s) (kV), length of distribution line (km), number of substations and approximate total supply capacity (MW):

Please see Item #5 above and attached letter and Schedules.

Item #12 – Affiliates of the Applicant:

12(a) Please provide the following information for all Affiliates of the Applicant

We have provided the requested information for TAGP's pertinent affiliates (as discussed with a Project Advisor in the OEB's Licence Applications division). A corporate organization chart is provided under Item #12(b) below.

TransAlta Cogeneration Limited Partnership (TCLP)
110 – 12 Avenue SW
Calgary, Alberta T2R 0G7
Telephone: 403-267-4688
Facsimile: 403-267-2575
Email: regulatory_legal@transalta.com
Generator License EG-2003-0184

Description of Business Activities: Like TAGP, TCLP is also in the business of electricity generation in the Province of Ontario. TCLP is 50% owner and operator of three cogeneration plants in Mississauga, Windsor and Ottawa. All three facilities supply electricity to the provincial grid via the IESO under long term contracts.

Canadian Hydro Developers Inc. (CHD)
110 – 12 Avenue SW
Calgary, Alberta T2R 0G7
Telephone: 403-267-4688
Facsimile: 403-267-2575
Email: regulatory_legal@transalta.com
Generator License EG-2003-0134

AND

Canadian Renewable Energy Corp. (CREC)
110 – 12 Avenue SW
Calgary, Alberta T2R 0G7
Telephone: 403-267-4688
Facsimile: 403-267-2575
Email: regulatory_legal@transalta.com
Generator License EG-2003-0013

Description of Business Activities: CHD is a wholly owned subsidiary of TransAlta Corporation and CREC is a wholly owned subsidiary of CHD. CHD and CREC own and operate a number of hydro and wind facilities in Ontario, Alberta and British Columbia.

TransAlta Energy Marketing Corp. (TEMC)
110 – 12 Avenue SW
Calgary, Alberta T2R 0G7
Telephone: 403-267-4688
Facsimile: 403-267-2575
Email: regulatory_legal@transalta.com
Wholesaler License EW-2011-0136

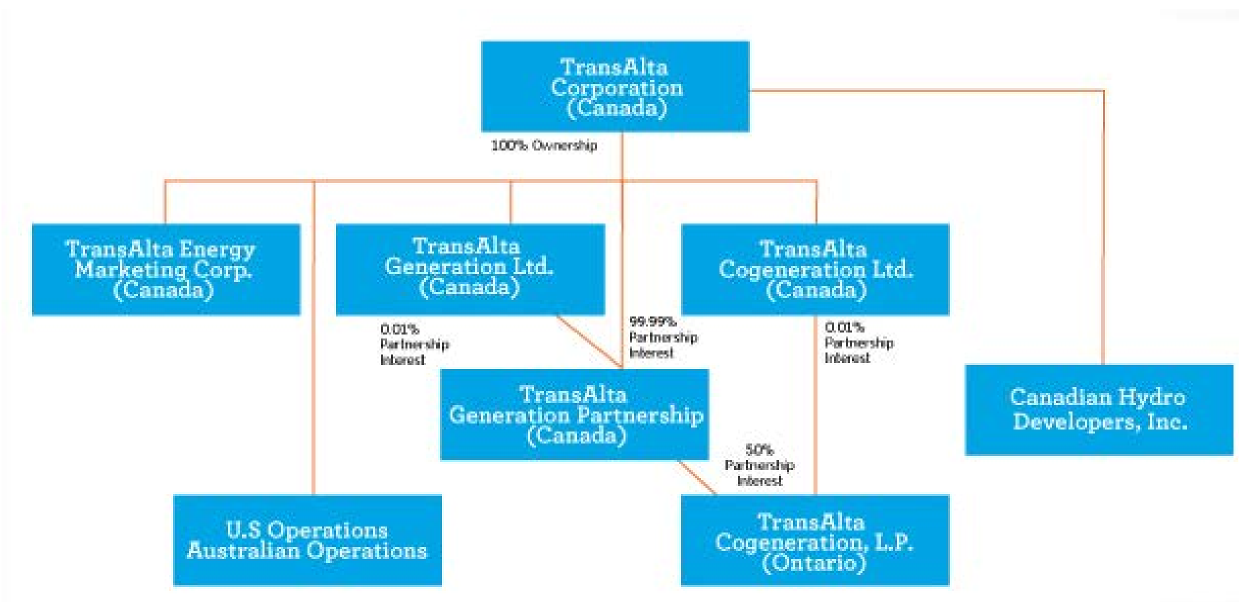
AND

<u>TransAlta Energy Marketing (U.S.) Inc. (TEMUS)</u>
110 – 12 Avenue SW
Calgary, Alberta T2R 0G7
Telephone: 403-267-4688
Facsimile: 403-267-2575
Email: regulatory_legal@transalta.com
Wholesaler License EW-2007-0601

Description of Business Activities: TEMC is responsible for optimizing the value of TransAlta's assets and for proprietary trading of energy products all over North America. Both TEMC and its US affiliate, TEMUS, are licensed electricity wholesalers in Ontario. Both TEMC and TEMUS conduct physical and financial trading of power in Alberta, PacNW, California, Desert SW, PJM, MISO, NEPOOL and Ontario. In addition, they also trade other products including Coal, Gas and Emissions.

For a list and description of all TransAlta generation facilities in Canada and elsewhere, please visit our website at www.transalta.com.

12(b) Please attach a Corporate organization chart describing the relationships between the Applicant and its Affiliates and, if applicable, the respective ownership percentages by the Applicant in each Affiliate.



<u>Item #13 – Energy Sector Activities:</u> Has the Applicant or an Affiliate undertaken any energy sector activities in Ontario or any other jurisdiction? Please provide details.

See Item #12(a) above.

<u>Item #14 – Business Activities:</u> Please provide a description of the Applicant's business activities

TAGP (Generator License EG-2009-0287) is in the business of electricity generation in the Provinces of Alberta and Ontario. TAGP owns and operates a 506 MW capacity generation facility located in Sarnia (SRCP) which provides thermal energy to several industrial customers in the area. The plant sells power directly to the IESO and also trades power in the Ontario market and holds bilateral agreements with industrial customers.

Item #15 – Technical Ability:

15(a) Please describe the applicant's technical ability to carry out the activities applied for including the Applicant's specific experience in Ontario and in other jurisdictions

As discussed above, TAGP is in the business of electricity generation in the Provinces of Alberta and Ontario. TAGP's parent company, TransAlta Corporation, has been in the business of electricity generation for over 100 years. For much of that period, the company owned and operated large-scale transmission and distribution assets throughout Alberta, bringing decades of experience to these sectors. The company has approximately $3 billion in annual revenue and more than $9 billion in assets, with power plants in Canada, the United States and Australia. TAGP is thus well-suited to carry out the proposed distribution activities.

A snapshot of the company's current operations in these countries can be found at the following link: http://www.transalta.com/sites/default/files/2012%20TransAlta%20QuickFacts.pdf

15(b) If the Applicant intends to utilize the capability of others by contracting distribution activities, please indicate below which activities and to whom they will be contracted

TAGP is still in the planning stages of this project and has not finalized which services (design, construction, etc.) will be outsourced to other companies. Any sub-contracts will be subject to a competitive bid process so that TAGP can ensure all work is carried out by reputable parties.

Item #16 – Information About Each Key Individual:

KEY INDIVIDUAL #1

Name: Mr. Peter R. Smith

Position Held: Director, Commercial Management East.

Please explain the person's experience in the electrical distribution business and in the energy field in general: Mr. Smith has almost 40 years experience in the energy industry. He has expertise in the design, construction, commissioning and operation of nuclear, gas and coal fired power plants. He has 12 years experience as manager of an industrial power plant with responsibility for the thermal energy and 13.8kV electrical distribution systems. He also has 10 years experience in business development and commercial management in the energy sector.

	Yes	No
a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.*	☐	☒
b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation?	☐	☒
c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled?	☐	☒

KEY INDIVIDUAL #2

Name: Mr. Trevor Gelinas

Position Held: Plant Manager, TransAlta Sarnia Regional Cogeneration Plant

Please explain the person's experience in the electrical distribution business and in the energy field in general: Mr. Gelinas has almost 23 years in the power generation industry for TransAlta. He has expertise in operation, maintenance, and commissioning of cogeneration, combined cycle and coal fired facilities. He has 11 years experience managing operations & maintenance, capital budgets and labour relations in the energy sector.

	Yes	No
a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.*	☐	☒
b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation?	☐	☒
c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled?	☐	☒

KEY INDIVIDUAL #3

Name: Mr. Gary Woods

Position Held: Director, TransAlta Gas Operations (Canada)

Please explain the person's experience in the electrical distribution business and in the energy field in general: Mr. Woods has 25 years experience in the energy industry, including 14 years in operations, maintenance and management of coal and gas fired power stations.

	Yes	No
a) Has this person been a proprietor, partner, officer or director of a business that was granted a licence under Part IV or Part V of the *Ontario Energy Board Act, 1998.*	☐	☒
b) Has this person been a proprietor, partner, officer, or director of a business that was registered or licenced under this or any other acts or legislation?	☐	☒
c) Has this person been a proprietor, partner, officer or director of a business that had a registration or licence of any kind refused, suspended, revoked or cancelled?	☐	☒

<u>Item #18 – Delivery:</u> Please indicate whether the Applicant's distribution facilities are to be used to deliver electricity to one or more parties other than the Applicant. If yes, please provide the following information:

18(a) If the purpose of the Applicant's distribution facilities is to provide distribution services to specific generators or load customers rather than the general public (see question #8) please indicate the names of these participants:

As discussed under Item #5 and in the attached letter, TAGP's proposed electricity distribution facilities will supply existing load at a site owned by LANXESS, as well as potential future load both on the LANXESS site and on the SRCP site. Again, we are still in the planning stage of this project and cannot provide names of additional load customers at this point (LANXESS is currently involved in confidential negotiations with various companies that are looking to build on its site).

18(b) a summary of the business plans relating to the Applicant's proposed distribution business for the next five years. This should include the following:

- **a forecast of annual growth in terms of factors such as the amount of electricity distributed (MW and/or MWH), number of customers served, amount of distribution facilities (lines and/or stations), etc.**
- **annual pro forma financial statements including forecasts of costs, revenues and project financing indicating the underlying assumptions on which the forecasts are based.**

As discussed above and in the attached letter, TAGP is still in the planning stage of this project. We cannot provide this information at this time.

18(c) estimates of net annual cash flows for subsequent periods to demonstrate financial feasibility and security.

As discussed above and in the attached letter, TAGP is still in the planning stage of this project. We cannot provide this information at this time.

18(d) indication of the Applicant's plans to seek Ontario Energy Board approval for electricity distribution rates.

TAGP will not charge LANXESS or any new load for the distribution of electricity.

<u>Item #19 – Proposed Business Transactions:</u> Please provide a brief summary of the expected impact of the proposed business transactions on the Ontario electricity market under the following headings:

19(a) Facilitate competition and enhance access to transmission/distribution services:

Not applicable – TAGP's proposed facilities will only supply new and existing load at the SRCP and LANXESS site.

19(b) Improve reliability and quality of supply:

As discussed in the attached letter, supplying LANXESS and new load via distribution facilities connected to the SRCP would provide a reliable means of securing electricity for these consumers. This would be a more environmentally sound approach than increasing the output at older, TAGP-owned generation. There would not need to be any new public utility connection assets built with the costs borne by LANXESS, the new load or other ratepayers. Under any of the electrical configurations shown in Schedules B, C or D to the attached letter, the LANXESS load and new load would continue to be supplied in the event that the SRCP went off-line. The proposed facilities will thus help protect the interests of consumers (i.e., LANXESS and new load) with respect to reliability and quality of electricity service.

19(c) Promote economic and energy efficiency:

As discussed in the attached letter, the impetus for the distribution facilities is to meet a contractual commitment to supply LANXESS in a way that is more economically and environmentally efficient than refurbishing old generation on the LANXESS site that TAGP owns. It would allow for increased expansion at the LANXESS site (through increased LANXESS load or the addition of a new business on vacant land at the LANXESS site without having to expand LANXESS' transformer connected to the Hydro One Networks Inc. system). It would also allow TAGP to "replace" the load that was lost when Dow Chemical closed its Sarnia operations in 2009. The proposed facilities will thus promote economic and cost efficiency in the generation, transmission and distribution of electricity.

APPENDIX “B” TO LICENCE APPLICATION

2010 Annual Report

100 Years ON

TransAlta

Financial Highlights

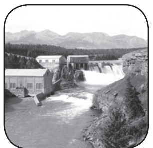
(in millions of Canadian dollars except per common share data and ratios)

Year ended Dec. 31	2010	2009	2008
Revenues	**2,819**	2,770	3,110
Net earnings applicable to common shares	**218**	181	235
Comparable earnings	**214**	181	290
Comparable EBITDA	**965**	888	1,006
Funds from operations	**783**	729	828
Cash flow from operations	**811**	580	1,038
Free cash flow (deficiency)	**204**	(117)	121
Per common share data *($)*			
Net earnings	**1.00**	0.90	1.18
Comparable earnings	**0.98**	0.90	1.46
Dividends paid	**1.16**	1.16	1.08
Ratios			
Cash flow to interest *(times)*	**4.3**	4.9	7.2
Cash flow to debt *(%)*	**18.3**	20.5	31.7
Debt to invested capital *(%)*	**53.6**	56.1	48.1
Comparable return on capital employed *(%)*	**6.1**	5.8	9.6

We’ve powered economic development and quality of life since 1911. Along the way, we’ve transformed ourselves from a regulated Alberta-based utility into an internationally diversified wholesale power producer and the largest publicly traded provider of renewable energy in Canada.

100 Years ON

Over the last century, TransAlta has established a first-mover advantage with the best sites, the best assets, a strong balance sheet, and a low-to-moderate risk profile. Our diversification has generated superb optionality for the next century.



1909-1919

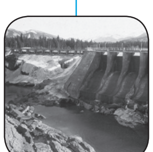
When Alberta was just four years old, we began our journey with the planning and construction of the Horseshoe Falls hydro plant. Two years later, we flipped the switch, and on Sunday morning, May 21, 1911, Calgary Power Company Ltd. began serving the people of Alberta.

1920-1929

Electricity is now being put to many new uses—from lighting up homes to revolutionizing kitchens—contributing to the exploration and early economic success of Alberta. During the booming 1920s, the company began providing electricity to more villages and towns in southern Alberta, expanding on its foundation as Alberta's most important electrical utility.

1930-1939

In the '30s, we toured our "Modern All-Electric Kitchen" trailer exhibit in the Calgary Stampede Parade and around Alberta. Electricity now powered refrigerators, coffee makers, washing machines, and mix masters. We supplied electricity to work camps as the oil and gas industry expanded after 1936 and we were fortunate and strong enough to continue operations without having to lay off a single employee during the Great Depression.



1940-1949

In 1941, the company purchased the Cascade hydro plant, rebuilt it and used its power to serve people in Banff and Canmore. Many employees enlisted to serve their country with the onset of the Second World War. And in 1947, after the discovery of a new oilfield at Leduc, near Edmonton, the company greatly expanded its service to the petroleum industry.

1950-1959

In the '50s, there were few potential hydro sites available for development in Alberta, but demand for power continued to grow. In 1956, the company began generating power at its first thermal plant at Lake Wabamun, moving the company to reliance on cheap and plentiful coal for most of its fuel. By 1958, the company had extended power to more than 30,000 farms across the province. In 1961, some 87 per cent of farmers had power.

1960-1969

In 1961, we marked our first 50 years of operation. We reached an agreement with the Alberta government to jointly construct a multi-use dam on the Brazeau River, which began making electricity in 1965. In 1963, the company began reclaiming land at its first coal mine at Whitewood, years before required by law. By the end of the decade we were building our second coal-fired facility at Sundance.

1970-1979

During the wild boom of the '70s, we continued to expand by fully commissioning the Sundance plant to keep up with the needs of a growing province. Society was also becoming more concerned about the environment, so we led by retro-fitting our generating plants with electrostatic precipitators, which removed 99.5 per cent of the fly ash from emissions.

1980-1989

In 1981, Calgary Power changed its name to TransAlta to reflect its broader mission. During the 1980s, we survived the deepest downturn since the Great Depression and commissioned Unit 6 at the Sundance plant. It incorporated the latest advances in generation technology along with our Keephills plant, the first generating facility to use computerized technologies. During this decade we expanded steadily, growing to supply 81 per cent of Alberta's electricity requirements.

1990-1999

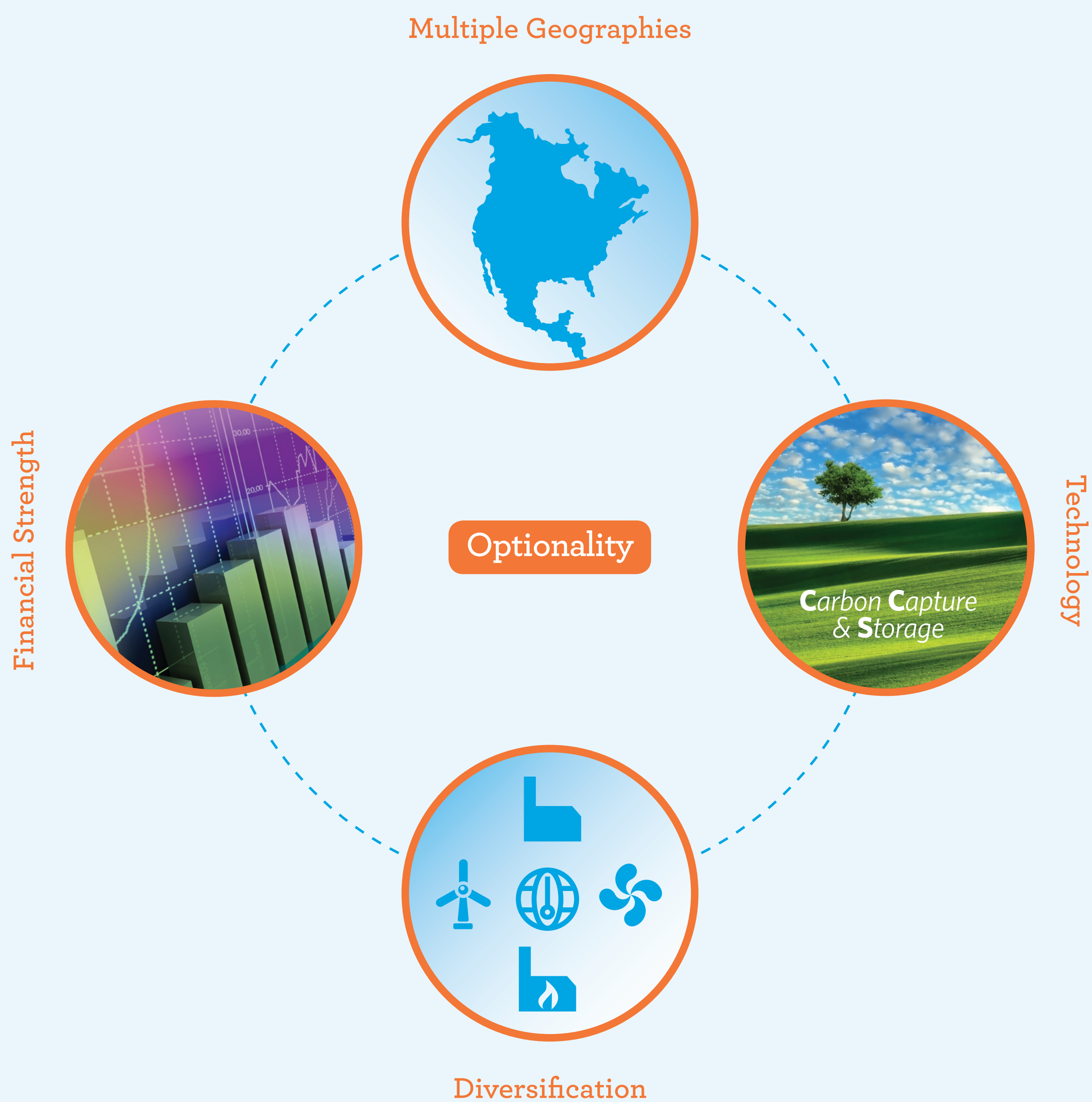
In the '90s, TransAlta expanded and built expertise in natural gas-fired generation with the Ottawa and Mississauga plants in Ontario as well as plants in Australia. We were the first Alberta utility to introduce an incentive program for energy efficiency and also made our first large investment in the wind power business in 1997. In 1999, we successfully bid on our first U.S. asset, a coal-fired plant in Centralia, Washington.

2000-2010

With deregulation now in effect, we divested our Alberta-based retail and distribution business, choosing instead to focus solely on power generation. Today, we are Canada's largest investor-owned wholesale power generation and marketing company and Canada's largest publicly traded provider of renewable energy.

Next Century

Optionality provides us with the flexibility to pursue the best growth opportunities; the ability to generate strong cash flow; the most choices for capital allocation; high margins and reduced volatility; and the greatest opportunity to deliver strong results for shareholders.



Letter to Shareholders

TransAlta delivered strong operating performance in 2010 and a 9% increase in comparable earnings per share over 2009.

We're proud of our results because we did well on pretty much everything that is under our control. This includes things like availability, growth projects, productivity initiatives, and reducing our cost structure.

Our challenge came from all those things we can't control. The anemic economy continued to roll over our industry—and it hurt. Persistent low natural gas prices (a key driver of power prices) depressed electricity prices to levels we saw a decade ago. Demand was down in many regions. Even the weather conspired against us with the lowest wind resource in 30 years in Q1, which is normally our best revenue quarter for wind generation, and the lowest water resources in 40 years in Q2, which is normally the best quarter of the year for hydro. Add to that a force majeure equipment failure at our Sundance 3 unit and you get the picture. These were taxing challenges, but our teams responded well and managed to recover most of the resulting shortfalls.

The fact is, our people and our plants were geared up to produce but we just couldn't get the natural resources or the dollars per gigawatt we wanted.

The good news is that our strong operational performance enabled us to hold our own in a tough market and demonstrated that we have great earnings potential under better market conditions.

More broadly, we take comfort from the fact that at a time of considerable uncertainty, TransAlta has a clear strategy, a very strong market position and a clear path to greater value. We are going to stay focused on our strategy and be patient as markets improve. And when they do, we will be there to take full advantage of the opportunities as they arise—from improved sales and margins, to asset growth.

TransAlta entered 2010 determined to take on three big challenges: (1) returning our thermal fleet to its historical high performance levels; (2) delivering on our growth plans; and (3) managing a range of risks during the biggest period of uncertainty our industry has faced. Let's look at how we performed against our major goals.

On the operations side, we set out to equal our best ever fleet availability performance of 90 per cent. Having delivered a disappointing availability level of only 85.1 per cent in 2009, this was a very aggressive stretch goal and we came oh so close, achieving fleet-wide availability of 88.9 per cent.

Steve Snyder
President & Chief Executive Officer

189 MW of growth delivered **on time** and **on budget**

The strong performance helped our revenues when prices were low, it energized our people, and it put us squarely back on track with our fleet performance. We are ready for 2011 and beyond.

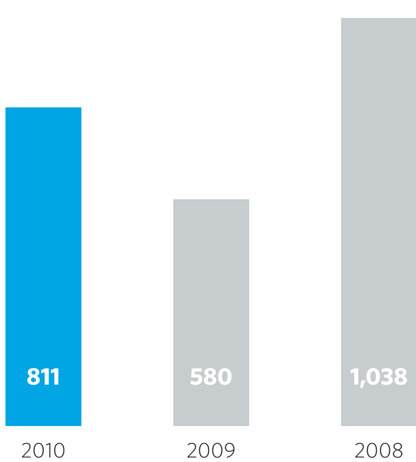
On the growth front, our teams did an outstanding job, adding 189 MWs of renewable wind power on time and on budget at three sites: Summerview II and Ardenville in southern Alberta, and Kent Hills in New Brunswick. We stayed on track with the projects we plan to deliver in 2011 and 2012. This includes Keephills 3, a state-of-the-art 450 MW supercritical coal plant, the 19 MW Bone Creek hydro project near Valemount, British Columbia, and three coal plant uprates. And we very successfully integrated our Canadian Hydro acquisition. With CanHydro, we added 694 MW of capacity and the related organization of nearly 150 employees in total. Yet at year-end, our total overhead costs were still less than 2009. That's a real productivity gain and real value created for our shareholders.

We also did well managing the uncertainty that has become an unfortunate fact of life for our industry. As I mentioned, electricity demand and power prices are weak. It is uncertain when demand will return, or what will happen to natural gas prices. The future direction, timing, and form of impending environmental policies are also uncertain. We entered 2010 with a strong sense that carbon pricing was imminent, as was legislation to cap emissions from coal plants in Canada. The former is now unlikely in the near term and the federal government is looking at the first half of 2011 to bring forth their legislation for coal emissions.

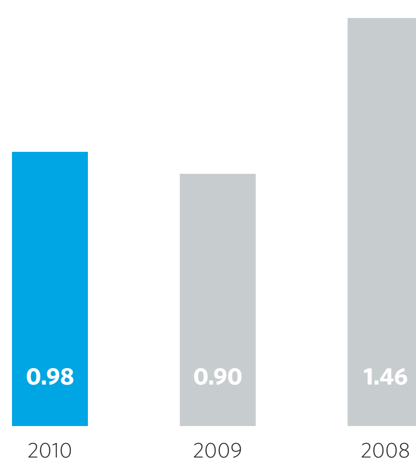
So how do we keep from going astray amidst all this uncertainty? We stay focused on our strategy and the creation of long-term sustainable shareholder value. That means we maintain a strong balance sheet, stay disciplined on capital allocation, protect our dividend, stick to a low-to-moderate risk profile, focus on operational excellence, and maximize our optionality through a multiple-fuel/multiple-geography approach.

This strategy has stood the test of time and provides a clear path through the uncertainty. It's easy to understand. It allows us to stay focused on execution. It protects shareowners in down cycles, delivers upside in the good ones, produces a strong yield, and uses disciplined asset expansion to grow the company. And it gives us as much strategic flexibility as you can have in a business with large, long-lived, and capital-intensive assets like power plants. Combined with our advantages as the incumbent provider in our main market, Alberta, this flexibility enables us to redeploy capital to its best use in a range of ways that are simply not available to less diversified companies and newer market entrants.

Cash Flow from Operations *($ millions)*



Comparable Earnings Per Share *($)*



TransAlta is **Canada's largest** publicly traded provider of renewable power

Last year I also highlighted three longer-term priorities we had set for ourselves.

1. DRIVE THE BASE By this we mean increasing productivity so that we can cost-effectively deliver sustained and sustainable, high-level plant performance. Our 2011 goal is to sustain the high availability performance we achieved in 2010. We are moving forward in 2011 to shift our plant control systems to digital technology, expand our operational diagnostic centre, and implement a major update of our plant system reporting capabilities. Each of these initiatives is designed to enhance our core operational efficiencies, speed up decision making, and lower both our operating and sustaining capital costs.

2. REPOSITION COAL While the specific form and timing remain uncertain and difficult to predict, we know carbon regulations are coming. We are an active participant in the ongoing policy discussion and we will be ready. We recently announced plans to develop a 700 MW natural gas-fired plant at our Sundance plant in support of retiring our older coal-fired units and transitioning to lower carbon power generation. We call this project Sun VII. And we continue to be a leader in developing Carbon Capture & Storage (CCS) technologies. Through our role in Project Pioneer, we are at the forefront of technological innovation and have front-row seats to a range of emerging CCS technologies. This knowledge will be very valuable in the future.

As I said last year, there is no quick fix to reduce carbon dioxide (CO_2) emissions in the electricity industry. Our industry is the economic engine of the regions we serve and a provider of an essential service. If we are to maintain the reliability and affordability of the electrical power we provide, we will need to work closely with policy-makers to develop a thoughtful long-term plan that recognizes the industry's large infrastructure investment and long-scale timelines. Our engineering and development teams are already at work on 20-year planning horizons to ensure we are ready to meet any future public policy changes and to maintain the long-term value of our immense coal reserves.

3. GREENING OUR PORTFOLIO Over the years TransAlta has developed one of the best green growth electricity portfolios in Canada. Current management can't take credit for TransAlta's entry to the renewable power sector in 1911 with the company's first hydro plant (which is still in operation). We can say, however, that we have spent the last decade developing fuel reserves, operating capabilities, and development expertise so that we can supply our customers with what they increasingly want—green power. TransAlta owns and operates nearly one-third of all of Canada's wind capacity, making us by far Canada's largest wind power generator. We've also developed a 10-year plan to upgrade our existing hydro system so it can continue to operate until the 22nd century. At the same time, we are looking at even bigger plans to add new capacity to our hydro fleet as the Alberta economy improves and the demand for power returns. And in the U.S., with our partner, CE Gen, we are poised to expand one of the best geothermal reserves in North America in the heart of that country's biggest and most environmentally conscious regional economy.

These priorities will continue to guide us as we go forward. They ensure we get the most out of our existing assets while we adapt to a rapidly changing industry landscape and remain an environmental leader.

TransAlta is Canada's largest publicly traded provider of renewable power. We also have major coal assets that generate very low cost power. This mix puts us smack in the middle of the climate change issue. We have not shied away from that debate. The essential service element of our product and the impact its costs have on consumers and our economy means it is too important for us to be a sideline player on this issue. As I mentioned, we have chosen to take a leadership position in the policy discussion and on technological innovation.

TransAlta has partnered with Alstom, Capital Power, and Enbridge on Project Pioneer, which will be one of the first large-scale CCS facilities in the world. We've looked at our oldest coal facilities and decided some of them could be replaced by lower-emitting natural gas facilities. We've taken the initiative to try and find a way to transition our Centralia Thermal plant in Washington State to a longer-term natural gas and renewable platform. And, we've grown our renewable fleet from 12 per cent of our production capacity in 2000 to 24 per cent today. For a capital-intensive business that's excellent performance by any standard.

Project Pioneer will be one of the **first large-scale** CCS facilities in the world

Our environmental leadership will continue. TransAlta is supportive of the federal government's plan to phase out coal plants at the end of a 45-year life. One area of concern, though, is the lack of action on developing new pricing mechanisms for carbon. We'll be the first to say that the last thing our economy needs right now is another cost burden, but without a price on carbon, the private sector simply won't have an incentive to develop technologies to reduce and/or contain carbon. And it's our strong belief at TransAlta that technology is the key to substantially reducing the world's production of CO_2. Conservation and increased efficiency are important and they will help, but they're not enough. Reducing demand in developing nations is unrealistic. Renewables remain costly and most are currently unable to supply base load power. So we will need clean coal and other new technologies if we are to meet our national social, economic, and environmental goals.

As we head into 2011, I can assure you our teams are ready for whatever may come at us. If it's another tough year for demand and prices we will keep our operating costs down and availability up as we work to squeeze every cent of earnings we can from the market. If conditions improve—and tough markets never last forever—we will be quick to jump on the opportunities. Our base is strong and efficient and we can quickly convert those opportunities into earnings.

This team is supported by an experienced, fully engaged, and knowledgeable Board. Their counsel is always available, sought, and freely given. At the same time, they hold themselves, management, and all our employees accountable to our shareholders and the highest levels of corporate governance and responsibility. In this regard, and on behalf of the entire management team and all of TransAlta's 2,200 employees, I want to offer my sincere thanks to Donna Soble Kaufman for her extraordinary commitment and leadership to TransAlta. After 22 years on our Board, the last six as Chair, Donna is not standing for re-election this year and we wish her all the very best.

I also want to express my appreciation to our shareholders for your support and loyalty. We don't take it lightly and we work hard to earn and keep it. Our company is sound. Our strategy is focused. We will hold our own in these tough times and deliver superbly in the good ones. And at all times our focus will be on delivering increasing shareholder value.

Sincerely,

Steve Snyder
President & Chief Executive Officer
March 04, 2011

Senior Management
(Standing left to right)
Ken Stickland
Chief Legal Officer
Dawn Farrell
Chief Operating Officer
Mike Williams
Chief Administration Officer
(Seated left to right)
Brett Gellner
Chief Financial Officer
Steve Snyder
President & Chief Executive Officer

Message from the Chair

2010, the first year of TransAlta's second century in business, marked another year of progress. We continued to press forward with an agenda of good governance and sustainable business practices, and we oversaw the ongoing creation of shareholder value through the steady and deliberate stewardship of TransAlta's assets and opportunities.

Donna Soble Kaufman
Chair of the Board

TransAlta enters 2011 as Canada's largest publicly traded generator and marketer of electricity. At a time of uncertainty on a number of fronts, we are well positioned for continued long-term growth, while maintaining our low-to-moderate risk profile. Our company has an experienced management team, dedicated employees, a strong balance sheet, an array of growth opportunities, and the industry's most diverse portfolio of assets and fuel sources.

This unique combination of capabilities gives TransAlta the strength to weather the current regulatory, environmental, and economic uncertainties, and the flexibility to capitalize on opportunities for growth as they emerge.

TransAlta's Board is guided by its accountability to our shareholders. Directors are fully engaged with management on the execution of TransAlta's long-term growth strategy. We have invested time and effort to ensure that TransAlta has appropriate risk mitigation policies and practices across the enterprise. We are diligent and disciplined in our capital allocation decisions. And we are focused, as always, on maintaining our commitment to pay a strong dividend.

Drawing on 100 years of experience, TransAlta continues to provide leadership in diversifying and expanding our power sources to meet the growing demand for clean, reliable and competitively priced electricity. Our active pursuit of carbon capture technology for cleaner coal-fired power stands at the forefront of global efforts to create a sustainable energy future. And this year, a third of TransAlta's electricity production came from natural gas and renewable energy sources.

We are proud of the recognition TransAlta has received for its dedication to environmental stewardship. In 2010 the company was again named to the Jantzi list of Canada's 50 most responsible corporations. For the fifth consecutive year, TransAlta was included in the Dow Jones Sustainability Index—once again, the only Canadian company in the utilities sector. And for the ninth consecutive year, The Globe and Mail recognized TransAlta as one of the best-governed companies in Canada.

We are committed to shareholder engagement, putting great effort into the governance of your Board. We are disciplined and rigorous in our efforts to provide complete transparency.

From a personal perspective, 2011 marks a significant milestone for me. After 22 years as a director of TransAlta—and having completed my six-year term as Chair—it is with deep gratitude, pride, and confidence in the company's future that I welcome my successor, Ambassador Gordon D. Giffin.

It has been a most rewarding journey, and I would like to extend my best wishes to Mr. Giffin, my fellow directors, our exceptional management team, and our more than 2,200 dedicated employees and retirees.

I would also like to offer my sincere thanks to our loyal shareholders for their support and confidence during my years of service to the Board.

It has truly been an honour and a privilege to serve on TransAlta's Board alongside such dedicated colleagues and a talented executive team.

I have every confidence that TransAlta will continue to flourish and capitalize on the many opportunities of its second century.

Sincerely,

Donna Kaufman

Donna Soble Kaufman
Chair of the Board
March 04, 2011

Board of Directors *(Standing left to right)* Stephen Baum; Martha Piper; Gordon Giffin; Timothy Faithful; Karen Maidment; Bill Anderson; Donna Soble Kaufman *(Seated left to right)* Michael Kanovsky; Kent Jespersen; Steve Snyder; Gordon Lackenbauer

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

Performance Metrics

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

Availability and Production

Our goal is to achieve consistent 89-90 per cent fleet availability and optimize production.

Availability is a key factor in determining revenue in many of our contracts. Availability is the percentage of time a generating unit is capable of running, regardless of whether or not it is generating electricity. Availability of 100 per cent over an extended period of time is not achievable as all plants require ongoing maintenance and experience, from time to time, unplanned outages.

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

	2010	2009	2008
Availability *(%)*	**88.9**	85.1	85.8
Production *(GWh)*	**48,614**	45,736	48,891

TransAlta greatly improved its availability in 2010 relative to the last two years, but fell just short of its 90 per cent target primarily as a result of the Sundance 3 High Impact Low Probability force majeure event. Improved availability was driven by lower planned and unplanned outages at Alberta Thermal and lower unplanned outages at Centralia Thermal.

Production increased as a result of higher availability and higher wind and hydro volumes resulting from the Canadian Hydro acquisition.

Productivity

Our goal is to offset the impact of inflation on Operations, Maintenance and Administration (OM&A) expenses.

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

	2010	2009	2008
OM&A *($/installed MWh)*	**7.97**	8.91	8.61

OM&A expenses per installed MWh decreased by over 10 per cent year-over-year primarily due to lower planned outages, cost savings from various productivity initiatives, and higher installed capacity.

TransAlta's target is to continue to manage OM&A costs through continuous productivity improvements in order to offset inflation. In addition, OM&A costs per installed MWh will be impacted going forward as a result of capitalizing major inspection costs under International Financial Reporting Standards (IFRS).

Sustaining Capital Expenditures

Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely over a long period of time.

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

	2010	2009	2008
Sustaining capex *($ millions)*	**308**	380	465

Sustaining capex in 2010 was directly in line with the target of $275-$320 million.

In 2011, sustaining capex is expected to be higher as a result of reporting under IFRS, which requires major inspection costs to be capitalized.

Safety

Our ultimate goal is to achieve zero injury incidents; targeting an Injury Frequency Rate (IFR) of 1 by 2015.

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

	2010	2009	2008
IFR	**1.19**	1.41	1.28

We significantly improved our IFR in 2010, achieving 1.19, the best in TransAlta's history. This puts us well on track to deliver on our goal.

EBITDA, Earnings, and Cash Flow

Our goal is to steadily grow comparable EBITDA, comparable EPS, and FFO on a trend-line basis over the commodity cycle.

Comparable Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) is frequently used to analyze and compare profitability between companies and industries because it eliminates the effects of financing and accounting decisions.

Comparable Earnings Per Share (EPS) is frequently used to measure a company's ongoing profitability.

Funds From Operations (FFO) is a measure of cash flow. It reflects the cash flow available to maintain our equipment, meet our debt repayment obligations, return capital to shareholders through dividends, and invest in new capacity.

	2010	2009	2008
EBITDA *($ millions)* (comparable basis)	**965**	888	1,006
EPS *($)* (comparable basis)	**0.98**	0.90	1.46
FFO *($ millions)*	**783**	729	828

Comparable EBITDA and comparable EPS increased year-over-year due to higher availability and production, the addition of higher margined renewable assets, and lower OM&A costs. Comparable EPS also increased due to lower depreciation expense.

Our FFO increased in 2010 to $783 million as a result of higher cash EBITDA, offset by higher interest expense due to the acquisition of Canadian Hydro.

In 2010, comparable EBITDA, comparable EPS, and FFO were negatively impacted by lower than historical wind and hydro levels.

Investment Ratios

Our goal is to maintain investment grade credit ratings.

Financial strength and flexibility are critical to the company's ability to create value, capitalize on opportunities, and manage industry cyclicality. The long-term ratios and ranges used to measure our performance include:

Cash flow to interest: 4-5x
Cash flow to debt: 20-25%
Debt to invested capital: 55-60%

	2010	2009	2008
Cash flow to interest *(times)*	**4.3**	4.9	7.2
Cash flow to debt *(%)*	**18.3**	20.5	31.7
Debt to invested capital *(%)*	**53.6**	56.1	48.1

In 2010, we maintained a strong balance sheet, financial ratios, ample liquidity, and investment grade credit ratings supported by our high level of contracting and low-to-moderate risk business profile. Cash flow to total debt decreased to just below our target due to higher debt levels associated with the acquisition of Canadian Hydro Developers and cyclically low power prices. In 2010, we initiated a three per cent discount on our dividend reinvestment and share puchase plan and issued $300 million of preferred shares to help support our goal of investment grade ratings, and as a result our debt levels decreased year-over-year.

Sustainable Long-Term Shareholder Value

Our goal is to achieve an average Return On Capital Employed (ROCE) and Total Shareholder Return (TSR) of 10 per cent per year over the long term.

We measure returns to our shareholders and investors through ROCE and TSR. ROCE is a measure of the efficiency and profitability of capital investments. TSR is the total amount returned to investors over a specific holding period and includes capital gains or losses and dividends.

Five-Year Rolling Average	**2010**	2009	2008
Comparable ROCE *(%)*	**8.0**	8.3	8.9[1]
TSR *(%)*	**2.0**	12.3	12.6

1 2008 ROCE based on a four-year rolling average.

In 2010, comparable ROCE increased to 6.1 per cent due to higher comparable earnings and higher EBITDA. ROCE has been below our goal due to low power prices and because TransAlta has invested a considerable amount of capital in new investments during the last few years that generate ROCE lower than target in the early part of the facility's economic life, but greater than target later on.

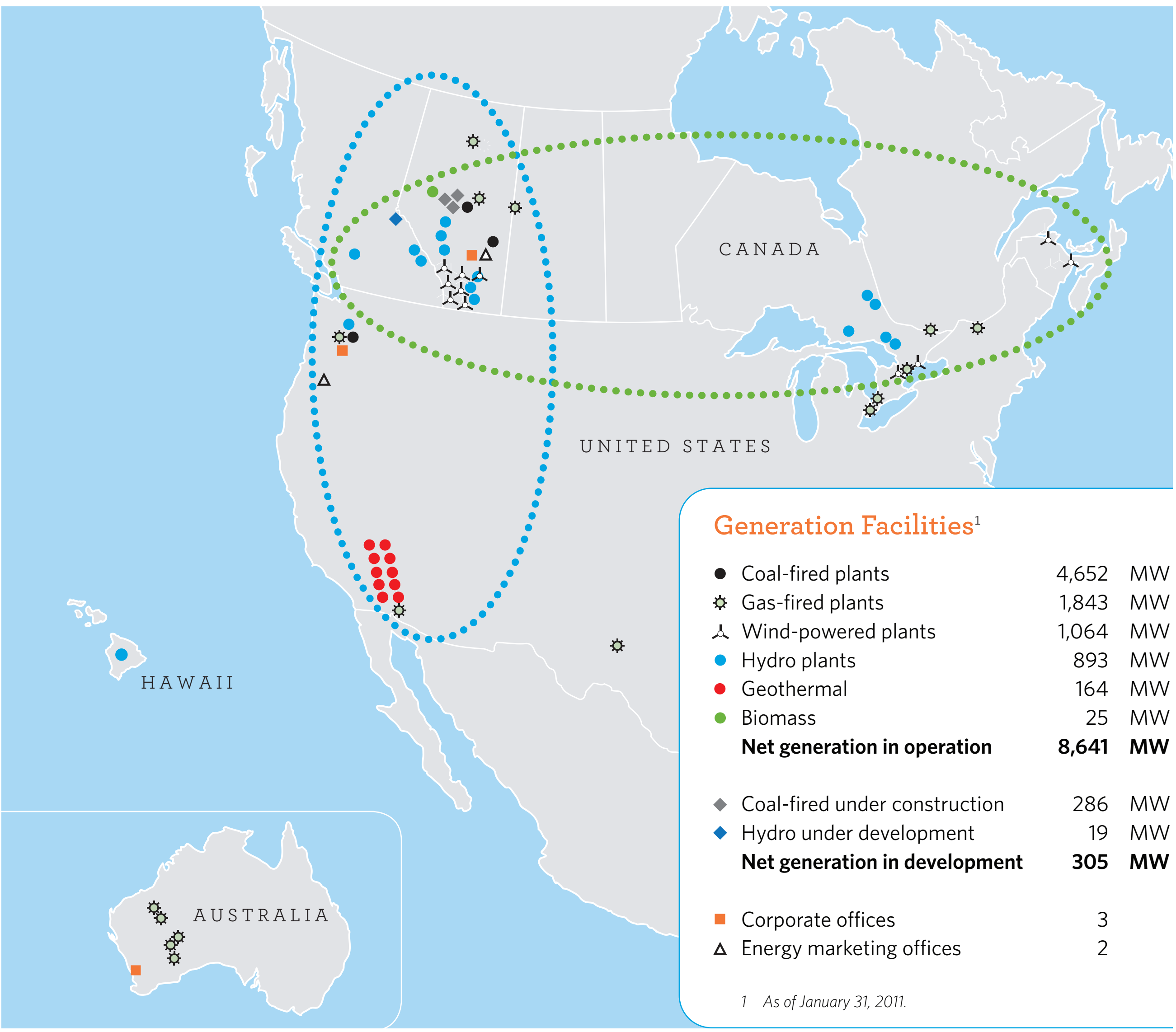
Given a slow economic recovery and low power prices, TransAlta's five-year rolling average TSR was below our goal in 2010.

Our Growing Geographic Reach

TransAlta is a leading provider of wholesale electrical power in Alberta and the Pacific Northwest, with a strong position in renewable energy across Canada.







Generation Facilities[1]

● Coal-fired plants	4,652	MW
Gas-fired plants	1,843	MW
Wind-powered plants	1,064	MW
● Hydro plants	893	MW
● Geothermal	164	MW
● Biomass	25	MW
Net generation in operation	**8,641**	**MW**
◆ Coal-fired under construction	286	MW
◆ Hydro under development	19	MW
Net generation in development	**305**	**MW**
■ Corporate offices	3	
△ Energy marketing offices	2	

1 *As of January 31, 2011.*

Plant Summary

As of January 31, 2011	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Fuel	Revenue source	Contract expiry date
Western Canada 42 Facilities	Sundance, AB[2]	2,141	100	2,141	Coal	Alberta PPA/ Merchant[3]	2017, 2020
	Keephills, AB[4]	812	100	812	Coal	Alberta PPA/ Merchant[4]	2020
	Keephills 3, AB[5]	450	50	225	Coal	Merchant	–
	Genesee 3, AB	450	50	225	Coal	Merchant	–
	Sheerness, AB	780	25	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100	356	Gas	LTC/Merchant	2024
	Fort Saskatchewan, AB	118	30	35	Gas	LTC	2019
	Meridian, SK	220	25	55	Gas	LTC	2024
	Brazeau, AB	355	100	355	Hydro	Alberta PPA	2020
	Big Horn, AB	120	100	120	Hydro	Alberta PPA	2020
	Spray, AB	103	100	103	Hydro	Alberta PPA	2020
	Ghost, AB	51	100	51	Hydro	Alberta PPA	2020
	Rundle, AB	50	100	50	Hydro	Alberta PPA	2020
	Cascade, AB	36	100	36	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100	19	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100	17	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100	15	Hydro	Alberta PPA	2013
	Horseshoe, AB	14	100	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100	13	Hydro	Alberta PPA	2020
	Taylor Hydro, AB	13	50	6	Hydro	Merchant	–
	Interlakes, AB	5	100	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100	3	Hydro	Merchant	–
	Three Sisters, AB	3	100	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100	3	Hydro	Merchant	–
	St. Mary, AB	2	100	2	Hydro	Merchant	–
	Upper Mamquam, BC	25	100	25	Hydro	LTC	2025
	Pingston, BC	45	50	23	Hydro	LTC	2023
	Bone Creek, BC[5]	19	100	19	Hydro	LTC	2031
	Akolkolex, BC	10	100	10	Hydro	LTC	2015
	Summerview 1, AB	70	100	70	Wind	Merchant	–
	Summerview 2, AB	66	100	66	Wind	Merchant	–
	Ardenville, AB	69	100	69	Wind	Merchant	–
	Blue Trail, AB	66	100	66	Wind	Merchant	–
	Castle River, AB[6]	44	100	44	Wind	LTC/Merchant	2011
	McBride Lake, AB	75	50	38	Wind	LTC	2023
	Soderglen, AB	71	50	35	Wind	Merchant	–
	Cowley Ridge, AB	21	100	21	Wind	Merchant	–
	Cowley North, AB	20	100	20	Wind	Merchant	–
	Sinnott, AB	7	100	7	Wind	Merchant	–
	Macleod Flats, AB	3	100	3	Wind	Merchant	–
	Taylor Wind, AB	3	100	3	Wind	Merchant	–
	Grande Prairie, AB	25	100	25	Biomass	LTC	2019-2024
	Total Western Canada	**6,788**		**5,403**			
Eastern Canada 13 Facilities	Sarnia, ON[7]	506	100	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50	54	Gas	LTC	2017
	Ottawa, ON	68	50	34	Gas	LTC	2012
	Windsor, ON	68	50	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100	7	Hydro	LTC	2011
	Misema, ON	3	100	3	Hydro	LTC	2027
	Galetta, ON	2	100	2	Hydro	LTC	2011
	Appleton, ON	1	100	1	Hydro	LTC	2011
	Moose Rapids, ON	1	100	1	Hydro	LTC	2011
	Wolfe Island, ON	198	100	198	Wind	LTC	2029
	Melancthon, ON	200	100	200	Wind	LTC	2026-2028
	Le Nordais, QC	99	100	99	Wind	LTC	2033
	Kent Hills, NB[8]	150	83	125	Wind	LTC	2033-2035
	Total Eastern Canada	**1,411**		**1,264**			
United States 17 Facilities	Centralia, WA[9]	1,340	100	1,340	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, CA[10]	327	50	164	Geothermal	LTC	2016-2029
	Skookumchuck, WA	1	100	1	Hydro	LTC	2020
	Wailuku, HI	10	50	5	Hydro	LTC	2023
	Total U.S.	**2,428**		**1,979**			
Australia 5 Facilities	Parkeston, WA	110	50	55	Gas	LTC	2016
	Southern Cross, WA[11]	245	100	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			
	TOTAL	**10,982**		**8,946**			

1 Megawatts are rounded to the nearest whole number
2 Includes a 15 MW uprate on unit 3 expected to be commercial in 2012
3 Merchant capacity refers to uprates on unit 4 (53 MW), unit 5 (53 MW), and unit 6 (44 MW)
4 Includes two 23 MW uprates on units 1 and 2 expected to be commercial in 2012 as merchant capacity
5 Facilities currently under development
6 Includes seven individual turbines at other locations
7 Sarnia's net maximum capacity (NMC) has been adjusted from 575 MW due to decommissioning of equipment at the facility
8 Includes Kent Hills 54 MW expansion that was completed in Q4 2010
9 Centralia Thermal's NMC has been reduced from 1,404 MW to reflect a lower plant output as a result of its conversion to burning Powder River Basin coal
10 Comprised of 10 facilities
11 Comprised of four facilities

For more information on TransAlta's facilities, please visit **www.transalta.com/facilities**

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited 2010 consolidated financial statements. Our 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, 2011. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including our 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. 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 2010, we began commercial operations at our Summerview 2, Kent Hills 2, and Ardenville wind farms, which added 189 megawatts ("MW") of renewable power to our generation portfolio. In 2010, we also decommissioned our 279 MW Wabamun coal plant.

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 in 2008 and 2009 resulted in zero to negative demand growth in our key markets. Alberta began to experience some demand growth in 2010 and this trend is expected to continue at a rate of approximately three per cent per year for the next three years. Cost reductions combined with relatively well-supported oil prices are expected to result in an increase in oil sands development which will, in turn, lead to higher electricity demand. Due to the economic recession, the Pacific Northwest has seen continued demand destruction in 2010. Demand growth in this region is expected to increase approximately two per cent per year over the next three years due to expectations of a modest economic recovery; however, the long-term growth rate is expected to be lower than historical trends because there is a large emphasis on energy efficiency across the region. Demand in Ontario increased in 2010 coincidental with overall economic growth. In the longer term, demand in Ontario is expected to remain virtually flat and increase less than one per cent per year over the next three years as a result of economic growth being offset by conservation measures.

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 the economic recovery continues 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 means that we expect our plants will continue to be supported in the market.

Transmission

Transmission refers to the bulk delivery system of power and energy between generating units and wholesale and/or retail customers. Power lines themselves serve as the physical path, transporting electricity from generating units to customers. Transmission systems are designed with sufficient reserve capacity to allow for "real time" fluctuations in both energy supply and demand caused by generation plants or loads increasing or decreasing output or consumption.

Transmission capacity refers to the ability of the transmission line, or lines, to safely and reliably transport electricity in an amount that balances the generating supply with the demand needs, and allows for 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, subject to extensive consultation processes with landowners, and subject to regulatory requirements that can change frequently. As a result, additions of generating capacity may not have ready access to markets until key bulk transmission upgrades and additions are completed.

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

Historically, transmission systems have been designed to serve loads in only their local area, and interties between jurisdictions that were built for reliability served 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 transmitting large quantities of electricity from one region to another. Such interregional lines will either be alternating current or direct current high voltage lines.

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").

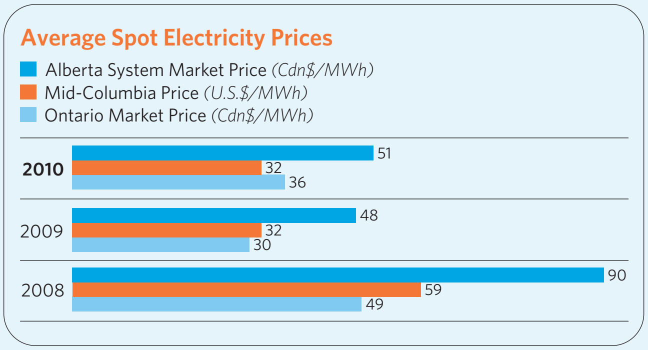
While Carbon Capture and Storage ("CCS") technologies are being developed, these technologies are not sufficiently advanced at this time. A $2 billion provincial fund and a $1 billion federal fund have been dispersed to several large demonstration projects. Project Pioneer, our CCS project, has qualified and received funding commitments of more than $750 million from these government initiatives. 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

The economic environment has shown signs of improvement in 2010 and we expect this trend to continue in 2011 at a slow to moderate pace.

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. The PPAs and long-term contracts covering a number of our generating facilities help minimize the impact of spot price changes.



The major markets we operate in are Western Canada, the U.S. Pacific Northwest, and Eastern Canada. 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.

For the year ended Dec. 31, 2010, average spot prices increased in both Alberta and Ontario, and were comparable in the Pacific Northwest compared to the same period in 2009. In Alberta, demand growth and high prices during the second quarter resulted in a higher annual price. In Ontario, prices increased due to demand recovery. In the Pacific Northwest, marginally higher gas prices were offset by lower weather-related demand.

During the year, our consolidated power portfolio was 95 per cent contracted through the use of PPAs and other long-term contracts. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2010 ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and from U.S.$50-$55 per MWh in the Pacific Northwest.

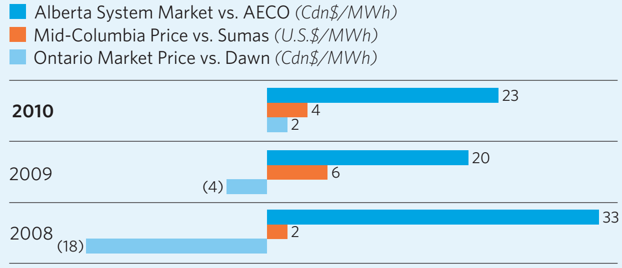
Spark Spreads

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 geographical region 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 Energy Trading business segments.

For the year ended Dec. 31, 2010, average spark spreads increased in Alberta and Ontario compared to the same periods in 2009 due to demand growth. Average spark spreads decreased in the Pacific Northwest compared to the same periods in 2009 due to lower weather-related demand during the third and fourth quarters, as well as increased generation from hydro and wind in the region.

Average Spark Spreads[1]



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

Strategy

Our goals are to deliver shareholder value by delivering solid returns through dividend yield, and disciplined comparable Earnings Per Share[2] ("EPS") and funds from operations[2] growth, while maintaining a low-to-moderate risk profile, balancing capital allocation, and maintaining financial strength. Our comparable EPS and funds from operations growth is driven by optimizing and diversifying our portfolio, growing our renewable portfolio across Canada, and 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 2010, although we started to see some demand growth, prices in our key markets remained consistent with the lower values experienced in 2009 as compared to prior years primarily due to the ongoing weak economic environment. While we are not immune to lower power prices, the impact of these lower prices is expected to be mitigated because approximately 88 per cent of 2011 and approximately 81 per cent of 2012 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 stable and predictable operations that are low cost and balanced with our fleet availability target. Our target for 2011 is to increase productivity and achieve overall fleet availability of 89 to 90 per cent. Over the last three years, our average availability has been 86.6 per cent, which is below our corporate target. The lower average availability has been primarily due to the accelerated planned maintenance undertaken in 2009 and higher than normal unplanned outages at our coal-fired plants in 2009 and 2008. In 2009, we reviewed each unit and developed asset-specific maintenance plans to achieve more predictable performance and stable operations, which were observed in 2010 by achieving overall availability of 88.9 per cent.

Growth Strategy

Our growth strategy is focused upon greening and diversifying our portfolio to reduce our carbon footprint and develop long-term, sustainable power generation. We've delivered on this plan in 2010 by completing our Summerview 2, Kent Hills 2, and Ardenville wind projects on time and on budget. We continue to develop opportunities for future sustainable power projects.

2 *Comparable EPS and funds from operations 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 EPS and funds from operations, including a reconciliation to net earnings and cash flow from operating activities.*

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 2010

Improve base operations	▪ Implemented productivity and cost reductions that lowered operating expenses across the fleet ▪ Implemented our revised major maintenance schedule on a unit-by-unit basis, which improved availability to 88.9 per cent in 2010 ▪ Began to align plans and capital spend for coal units based on the emerging proposal to reduce GHG emissions by their 45th year of operation ▪ Approved a 15 MW efficiency uprate at Unit 3 of our Sundance facility
Reposition coal	▪ Participated in the Front End Engineering and Design ("FEED") study to investigate the feasibility of Project Pioneer, which uses CCS technology and is expected to be completed in 2011 ▪ Announced Enbridge as an official partner in the development of Project Pioneer ▪ Signed a Memorandum of Understanding ("MOU") with the State of Washington and began plans to reduce GHG emissions from the Centralia Thermal plant ▪ Continued active involvement in environmental policy discussions with various levels of government in Canada and the U.S.
Green and diversify our portfolio	▪ Added 189 MW of wind generation to our portfolio by completing construction of the Summerview 2, Kent Hills 2, and Ardenville wind farms ▪ Continued our work on the construction of Bone Creek, a 19 MW hydro facility in British Columbia

Financial Strength

We manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline proved valuable during the weak economic environment of 2010 and will continue to be important during 2011. We continue to maintain $2.0 billion in committed credit facilities, and as of Dec. 31, 2010, $1.1 billion was available to us. Our investment grade credit rating, available credit facilities, strong funds from operations, and limited debt maturity profile provide us with financial flexibility, and as a result we can be selective as to 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 2010, we took advantage of favourable capital markets by completing a U.S.$300 million 30-year senior notes offering in March and completing the sale of $300 million of preferred shares in December. Both transactions were well received by the markets and were oversubscribed. Looking forward, we expect 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, and meeting 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 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 targeted rate of return. We currently have 305 MW of capacity under construction, which is comprised of 225 MW of coal-fired generation, 61 MW of uprates to our thermal coal fleet, and 19 MW of hydro. We also have more than 1,400 MW of advanced development wind, hydro, natural gas, 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 2010, we approved and began work on a 15 MW uprate on Unit 3 of our Sundance plant ("Unit 3"), and in 2011 we will continue our work on the Unit 3 uprate, as well as the uprates of Units 1 and 2 of our Keephills plant.

People

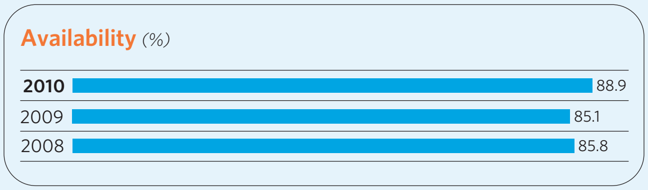
Our experienced leadership team is comprised of senior business leaders who bring a broad mix of skills in the electricity sector, finance, law, government, regulation, and corporate governance. The leadership team's experience and expertise, our employees' knowledge and dedication to superior operations,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

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

We strive to optimize the availability of our plants 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, as well as 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, balancing our maintenance costs with optimal availability targets. Over the past three years we have achieved an average availability of 86.6 per cent, which is below our long-term target of 89 to 90 per cent. Our availability in 2010 was 88.9 per cent.

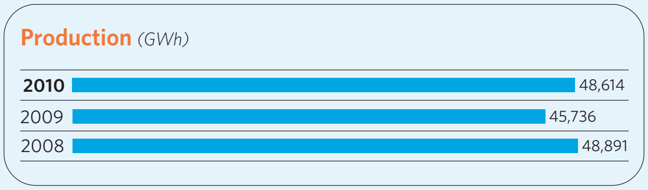


Availability for the year ended Dec. 31, 2010 increased compared to 2009 primarily due to lower planned outages at our Keephills plant, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal.

Availability for the year ended Dec. 31, 2009 decreased due to higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, 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, lower planned and unplanned outages at Genesee 3, and lower unplanned outages at Keephills.

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.

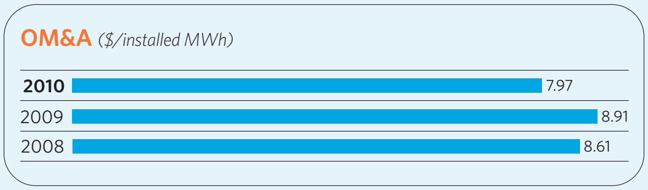


Production for the year ended Dec. 31, 2010 increased 2,878 gigawatt hours ("GWh") compared to 2009 as a result of higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro"), lower planned and unplanned outages at our Sundance plant, lower unplanned outages at Centralia Thermal, lower planned outages at our Keephills plant, and lower economic dispatching at Centralia Thermal, partially offset by the decommissioning of Wabamun, higher planned outages at Centralia Thermal and Genesee 3, and the expiration of the long-term contract at Saranac.

Production for the year ended Dec. 31, 2009 decreased 3,155 GWh due to higher economic dispatching and higher unplanned outages at Centralia Thermal, higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower PPA customer demand, 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, lower planned and unplanned outages at Genesee 3, and lower unplanned outages at Keephills.

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, 2010, OM&A costs per installed MWh decreased compared to 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, combined with higher installed capacity primarily as a result of the acquisition of Canadian Hydro.

For the year ended Dec. 31, 2009, OM&A costs per installed MWh 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.

Safety

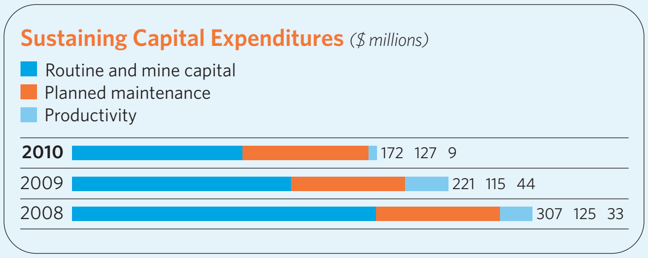
Safety is a top priority with all of our staff, contractors, and visitors. Our objective is to improve safety by reducing our Injury Frequency Rate ("IFR") to 1 by 2015. Our ultimate goal is to achieve zero injury accidents.

	2010	2009	2008
IFR	**1.19**	1.41	1.28

In 2010, the IFR decreased due to fewer injuries at our coal facilities, primarily at the Sundance plant, as a direct result of continuous efforts to improve safety. 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.

Sustaining Capital Expenditures

We are in a long-cycle capital-intensive business that requires consistent and stable capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely over a long period of time. Our sustaining capital is comprised of three components: (1) routine and mine capital, (2) planned maintenance, and (3) productivity.



In 2010, we spent $49 million less on routine and mine capital, $12 million more on planned maintenance, and $35 million less on productivity compared to 2009. The decrease in routine and mine capital was due to decreased spending on equipment modifications at Centralia Thermal, lower mine capital at the Highvale mine, which supplies coal to both our Keephills and Sundance plants, and lower routine spending at Sarnia. Planned maintenance increased primarily due to higher spending on renewables as a result of the acquisition of Canadian Hydro. The decrease in productivity expenditures was primarily due to lower spend on turbine uprates at Mississauga and Windsor.

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.

Earnings and Funds from Operations

We focus our base business on delivering strong earnings and funds from operations growth. Our goal is to steadily grow comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"), comparable EPS, and funds from operations over the long term, recognizing that the amount of growth may fluctuate year-over-year with the commodity cycle.

	2010	2009	2008
Comparable EPS	**0.98**	0.90	1.46
Comparable EBITDA[1]	**965**	888	1,006
Funds from operations	**783**	729	828

1 *Comparable EBITDA is not defined under Canadian GAAP. Presenting comparable EBITDA 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 EBITDA, including a reconciliation to net earnings.*

In 2010, comparable EPS and comparable EBITDA increased compared to the same period in 2009 primarily due to higher availability and production, and lower OM&A costs. Comparable EPS also increased in 2010 due to lower depreciation expense.

In 2009, comparable EPS and comparable EBITDA decreased due to higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower hydro volumes and prices, and lower trading margins.

In 2010, funds from operations increased compared to the same period in 2009 due to higher availability and production, and lower operational expenditures, partially offset by higher interest payments due to the acquisition of Canadian Hydro and lower than historical wind and hydro volumes. In 2009, funds from operations decreased due to lower availability and production, and the receipt of an additional PPA payment 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.

	2010	2009	2008
Cash flow to interest coverage (times)	**4.3**	4.9	7.2
Cash flow to debt (%)	**18.3**	20.5	31.7
Debt to invested capital (%)	**53.6**	56.1	48.1

Cash flow to interest coverage decreased in 2010 compared to the same period in 2009 primarily due to higher interest expense. Cash flow to interest coverage decreased in 2009 as a result of lower funds from operations and higher interest expense. Our goal is to maintain this ratio in a range of four to five times.

Cash flow to debt decreased in 2010 compared to the same period in 2009 due to higher average debt levels in 2010. Cash flow to debt decreased in 2009 due to a decrease in funds from operations and higher debt as a result of our issuances of senior and medium-term notes during 2009 to fund the acquisition of Canadian Hydro. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital decreased as at Dec. 31, 2010 compared to the same date in 2009 due to the favourable impact of a stronger Canadian dollar on our U.S. dollar denominated debt. Debt to invested capital increased in 2009 as a result of the issuance of debt throughout the year to fund growth and for the acquisition of Canadian Hydro. Our goal is to maintain this ratio in a range of 55 to 60 per cent.

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 goal is to grow our comparable Return On Capital Employed ("ROCE")[1] and Total Shareholder Return ("TSR")[1] by achieving a return of 10 per cent per year over the long-term.

The table below shows our historical performance and targets on these measures on a five-year rolling average:

	2010	2009	2008
Comparable ROCE (%)[2]	**8.0**	8.3	8.9
TSR (%)	**2.0**	12.3	12.6

2 2008 comparable ROCE is based on a four-year rolling average as we did not begin reporting comparable ROCE until 2005.

The five-year rolling average of comparable ROCE has decreased slightly due to higher debt levels primarily due to the acquisition of Canadian Hydro in 2009, partially offset by increasing comparable earnings year-over-year.

The five-year rolling average of TSR has decreased due to the decline of our stock price, which is a direct result of the economic recession that began in 2008 that has been slow to recover.

1 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 Accumulated Other Comprehensive Income ("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

Our results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading[1] and Corporate. 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 relating to self-sustaining foreign operations is reflected in the equity section of the Consolidated Balance Sheets.

Highlights and Summary of Results

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

Year ended Dec. 31	**2010**	2009	2008
Availability (%)	**88.9**	85.1	85.8
Production (GWh)	**48,614**	45,736	48,891
Revenues	**2,819**	2,770	3,110
Gross margin[2]	**1,617**	1,542	1,617
Operating income[2]	**497**	378	533
Net earnings applicable to common shares	**218**	181	235
Net earnings per common share, basic and diluted	**1.00**	0.90	1.18
Comparable EPS	**0.98**	0.90	1.46
Comparable EBITDA	**965**	888	1,006
Funds from operations	**783**	729	828
Cash flow from operating activities	**811**	580	1,038
Cash flow from operating activities per share[2]	**3.70**	2.89	5.22
Free cash flow (deficiency)[2]	**204**	(117)	121
Dividends paid per common share	**1.16**	1.16	1.08

As at Dec. 31	**2010**	2009	2008
Total assets	**9,893**	9,786	7,824
Total long-term liabilities	**5,108**	5,548	3,645

2 *Gross margin, operating income, cash flow from operating activities per share, and free cash flow (deficiency) are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings and cash flow from operating activities.*

1 *Our Energy Trading segment was referred to as "Commercial Operations and Development" in 2009 and 2008.*

Reported Earnings

The primary factors contributing to the change in net earnings applicable to common shares for the years ended Dec. 31, 2010 and 2009 are presented below:

Net earnings applicable to common shares for the year ended Dec. 31, 2008	235
Decrease in Generation gross margins	(33)
Mark-to-market movements – Generation	16
Decrease in Energy Trading gross margins	(58)
Increase in operations, maintenance, and administration costs	(30)
Increase in depreciation expense	(47)
Asset impairment charges	(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
Increase in foreign exchange gain	20
Net earnings applicable to common shares for the year ended Dec. 31, 2009	181
Increase in Generation gross margins	36
Mark-to-market movements – Generation	45
Decrease in Energy Trading gross margins	(6)
Decrease in operations, maintenance, and administration costs	33
Decrease in depreciation expense	16
Asset impairment charges	(73)
Increase in net interest expense	(34)
Decrease in other income	(8)
Decrease in non-controlling interests	18
Decrease in income tax expense	14
Other	(4)
Net earnings applicable to common shares for the year ended Dec. 31, 2010	**218**

For the year ended Dec. 31, 2010, Generation gross margins, excluding the impact of mark-to-market movements, increased compared to the same period in 2009 due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, lower planned and unplanned outages at our Sundance plant, and lower planned outages at our Keephills plant, partially offset by unfavourable pricing, the expiration of the long-term contract at Saranac, the decommissioning of Wabamun, and unfavourable foreign exchange rates.

In 2009, Generation gross margins, excluding the impact of mark-to-market movements, decreased due to higher planned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, 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, lower unplanned outages at Keephills, higher wind volumes due to the acquisition of Canadian Hydro and the commissioning of Kent Hills, favourable foreign exchange rates, and favourable contractual pricing.

Mark-to-market movements increased for the year ended Dec. 31, 2010 primarily due to the recognition of unrealized gains resulting from certain power hedging relationships being deemed ineffective for accounting purposes.

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased compared to the same period in 2009 primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

In 2009, Energy Trading 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.

For the year ended Dec. 31, 2010, OM&A costs decreased compared to the same period in 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by the acquisition of Canadian Hydro.

In 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.

For the year ended Dec. 31, 2010, depreciation expense decreased compared to the same period in 2009 due to a change in the estimated useful lives of certain coal generation facilities and mining assets, a reduction in the estimated costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

In 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.

During the fourth quarter of 2010, we recorded pre-tax asset impairment charges of $89 million related to certain coal and natural gas facilities. Refer to the Asset Impairment section of this MD&A for further details.

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 Westfield site was placed on hold indefinitely and in 2009, the costs that had been capitalized were expensed.

For the year ended Dec. 31, 2010, net interest expense increased compared to the same period in 2009 due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

In 2009, net interest expense increased 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 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. The sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

For the year ended Dec. 31, 2010, non-controlling interests decreased compared to the same period in 2009 due to lower earnings resulting from the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TA Cogeneration, L.P. ("TA Cogen").

In 2009, non-controlling interests decreased primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac.

For the year ended Dec. 31, 2010, income tax expense decreased compared to the same period in 2009 as a result of the resolution of certain outstanding tax matters, partially offset by higher pre-tax earnings.

In 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.

Significant Events

Our consolidated financial results include the following significant events:

2010

Sale of Meridian
On Dec. 20, 2010, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, all associated assets and liabilities have been classified as held for sale under the Generation segment. The sale is effective Jan. 1, 2011 and is expected to close in early 2011. The impact of this transaction on net earnings is not expected to be significant.

Purchase Price Allocation Adjustment
During the fourth quarter of 2010, management updated the preliminary purchase price allocation related to our acquisition of Canadian Hydro to better reflect the value of the underlying assets and liabilities acquired. As a result, a $114 million adjustment was made to depreciable assets, producing a $4 million decrease in depreciation expense. The adjustment to depreciable assets was offset by adjustments to goodwill and future income taxes.

Sundance Unit 1 and 2 Outage
On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of our Sundance facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units were unavailable as inspections were carried out to determine the scope of repairs that may be needed. The units cannot be restarted without inspection and approval from the Alberta Boiler Safety Association. As a result of the outage, production was reduced by 182 GWh for the year ended Dec. 31, 2010.

Under the terms of the PPA for these units, we have notified the PPA Buyer and the Balancing Pool of a force majeure event. Under force majeure, we are entitled to receive our PPA capacity payments and are protected from having to pay penalties for the units' lack of availability, to the extent the event meets the force majeure criteria set out in the PPA.

On Feb. 8, 2011, we announced that we had issued a notice of termination for destruction on our Sundance 1 and 2 coal-fired generation units under the terms of the PPA. This action was based on our determination that the physical state of the boilers is such that the units cannot be economically restored to service under the terms of the PPA. Under the PPA, termination for destruction permits the recovery of the net book value specified in the PPA.

On Feb. 18, 2011, the PPA Buyer has provided notice that it intends to dispute our notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. Although no assurance can be given as to the ultimate outcome of these matters, we believe that they will be resolved in our favour. We remain committed to continuing to work with the PPA Buyer and the Balancing Pool under the processes established within the PPA.

Resolution of Tax Matters

During 2010, we recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters, which was received in 2010. Interest expense also decreased by $14 million as a result of tax-related interest recoveries.

Sale of Preferred Shares

On Dec. 10, 2010, we completed our public offering of 12 million Series A 4.60 per cent Cumulative Rate Reset First Preferred Shares, resulting in gross proceeds of $300 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Kent Hills 2

On Nov. 21, 2010, the 54 MW expansion of our Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010, and an additional $2 million of proceeds related to costs expected in 2011. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

Ardenville

On Nov. 10, 2010, our 69 MW Ardenville wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $135 million.

Project Pioneer

On Nov. 28, 2010, we announced that the Global Carbon Capture and Storage Institute awarded the Corporation AUD$5 million to share knowledge around the world from Project Pioneer, Canada's first fully integrated CCS project involving retrofitting a coal-fired generation plant. The funding will help Project Pioneer both contribute to and access international research and leading-edge knowledge from a global CCS forum.

On June 28, 2010, we announced that Enbridge Inc. ("Enbridge") will officially participate as a partner in the development of Project Pioneer.

Sundance Unit 3 Uprate

On Sept. 13, 2010, we obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of our Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed chief financial officer, succeeding Brian Burden, who made a personal decision to retire from the Corporation. Mr. Burden assisted Mr. Gellner with the transition through Sept. 30, 2010.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 of our Sundance facility due to the mechanical failure of critical generator components. As a result, the expected capability levels for Unit 3 were reduced. Unit 3 returned to service at the reduced expected capability levels on June 23, 2010. The unit continues to operate at these reduced levels and no assurance can be given as to whether it will return to normal operating levels prior to the completion of major maintenance currently scheduled for the middle of 2012. As a result of the outage and subsequent derate, production was reduced by 480 GWh for the year ended Dec. 31, 2010.

In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. During the second quarter, we recorded an after-tax charge of $13 million, or 50 per cent of the penalties to June 30, 2010, representing the amount of penalties we are required to pay to the PPA Buyers pending a resolution of this matter. No additional penalties relating to this event were incurred during the year.

On Oct. 20, 2010, the Balancing Pool confirmed it agreed with our determination that the mechanical failure meets the requirements of a HILP event under the PPA. While this decision neither constitutes a determination of a force majeure event, nor provides a definitive resolution to the dispute, management believes this strengthens our position with regards to financial protection from the event.

Dividend Reinvestment and Share Purchase ("DRASP")

On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. Under the terms of our DRASP plan, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. The Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

Centralia Thermal MOU

On April 26, 2010, we announced that we signed an MOU with the State of Washington to enter discussions to develop an agreement to significantly reduce GHG emissions from the Centralia Thermal plant, and to provide replacement capacity by 2025. The MOU also recognizes the need to protect the value that Centralia Thermal brings to our shareholders. Discussions are ongoing and details on the results of these discussions will be provided as they become available.

Decommissioning of Wabamun Plant

On March 31, 2010, we fully retired all units of the Wabamun plant as part of our previously announced shutdown. Over the next several years, we will complete the Wabamun plant remediation and reclamation work as approved by the Government of Alberta. Based on our review of our schedule and detailed costing of the decommissioning and reclamation activities, the asset retirement obligation associated with the Wabamun plant was reduced by $14 million during the first quarter of 2010, with the offset recorded as a recovery in depreciation.

Senior Notes Offering

On March 12, 2010, we completed our offering of U.S.$300 million senior notes maturing in 2040 and bearing an interest rate of 6.50 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

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 approximately $118 million.

Change in Economic Useful Life

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, our economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to the same period in 2009.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

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 $396 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 MacLeod 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 objectives.

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 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, Capital Power Corporation ("Capital Power"), and Enbridge. The FEED study is expected to be completed in 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 had 9,199 MW of gross generating capacity[1] in operation (8,775 MW net ownership interest). The combined renewables portfolio included more than 1,900 MW in operation, or 22 per cent of our total portfolio at that time. In addition, there was a combined 424 MW net under construction and over 600 MW in advanced-stage development at Dec. 31, 2009.

The following table depicts the impact of Canadian Hydro on our consolidated operations portfolio by geographic region and fuel type at Dec. 31, 2009:

Net Capacity Ownership Interest (MW)

Dec. 31, 2009	Canadian Hydro	TransAlta[2]	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
Biomass	25	–	25
Geothermal	–	164	164
Wind	583	300	883
Hydro	86	807	893
	694	8,081	8,775

2 Excluding Canadian Hydro.

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.

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 provided 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 was approximately $135 million. Included in the capital cost of the project was the purchase of an already operational 3 MW turbine at Macleod Flats. Commercial operations of the Ardenville wind project began on Nov. 10, 2010.

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, 2009 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, we gave notice of a HILP event and claimed force majeure relief 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 HILP force majeure event. As a result, we also recorded an additional charge in the second quarter of 2009 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 both units expected 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 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. 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 of Directors 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 approximately $118 million and commercial operations commenced on Feb. 23, 2010.

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 Regulation 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.

Discussion of Segmented Results

GENERATION: Owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, 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, 2010, Generation had 9,109 MW of gross generating capacity in operation (8,676 MW net ownership interest) and 305 MW (net ownership interest) under construction. 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 2010, we began commercial operations at our Summerview 2, Kent Hills 2, and Ardenville wind farms, which added 189 MW of renewable power to our generation portfolio. In 2010, we also decommissioned our 279 MW Wabamun plant. 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 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 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	**2010**		2009		2008	
	Total	**Per installed MWh**	Total	Per installed MWh	Total	Per installed MWh
Revenues	**2,778**	**34.90**	2,723	36.37	3,005	40.63
Fuel and purchased power	**1,202**	**15.10**	1,228	16.40	1,493	20.18
Gross margin	**1,576**	**19.80**	1,495	19.97	1,512	20.45
Operations, maintenance, and administration	**549**	**6.90**	550	7.35	487	6.58
Depreciation and amortization	**438**	**5.50**	453	6.05	409	5.53
Taxes, other than income taxes	**27**	**0.34**	22	0.29	19	0.26
Intersegment cost allocation	**5**	**0.06**	32	0.43	30	0.41
Operating expenses	**1,019**	**12.80**	1,057	14.12	945	12.78
Operating income	**557**	**7.00**	438	5.85	567	7.67
Installed capacity (GWh)	**79,591**		74,866		73,969	
Production (GWh)	**48,614**		45,736		48,891	
Availability (%)	**88.9**		85.1		85.8	

Generation Production and Gross Margins

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

Year ended Dec. 31, 2010	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
Coal	**25,025**	**31,325**	**813**	**335**	**478**	**25.95**	**10.69**	**15.26**
Gas	**3,981**	**4,866**	**232**	**76**	**156**	**47.68**	**15.62**	**32.06**
Renewables	**2,506**	**11,120**	**142**	**10**	**132**	**12.77**	**0.90**	**11.87**
Total Western Canada	**31,512**	**47,311**	**1,187**	**421**	**766**	**25.09**	**8.90**	**16.19**
Gas	**3,816**	**6,570**	**435**	**243**	**192**	**66.21**	**36.99**	**29.22**
Renewables	**1,330**	**5,435**	**126**	**7**	**119**	**23.18**	**1.29**	**21.89**
Total Eastern Canada	**5,146**	**12,005**	**561**	**250**	**311**	**46.73**	**20.82**	**25.91**
Coal	**8,594**	**12,053**	**773**	**470**	**303**	**64.13**	**38.99**	**25.14**
Gas	**2,063**	**6,736**	**140**	**56**	**84**	**20.78**	**8.31**	**12.47**
Renewables	**1,299**	**1,486**	**117**	**5**	**112**	**78.73**	**3.36**	**75.37**
Total International	**11,956**	**20,275**	**1,030**	**531**	**499**	**50.80**	**26.19**	**24.61**
	48,614	**79,591**	**2,778**	**1,202**	**1,576**	**34.90**	**15.10**	**19.80**

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
Coal	24,517	32,833	838	349	489	25.52	10.63	14.89
Gas	4,035	4,744	228	79	149	48.06	16.65	31.41
Renewables	1,891	8,757	116	7	109	13.25	0.80	12.45
Total Western Canada	30,443	46,334	1,182	435	747	25.51	9.39	16.12
Gas	3,377	6,570	388	224	164	59.06	34.09	24.97
Renewables	452	1,686	40	1	39	23.72	0.59	23.13
Total Eastern Canada	3,829	8,256	428	225	203	51.84	27.25	24.59
Coal	7,450	12,053	767	476	291	63.63	39.49	24.14
Gas	2,637	6,736	213	82	131	31.62	12.17	19.45
Renewables	1,377	1,486	133	10	123	89.50	6.73	82.77
Total International	11,464	20,275	1,113	568	545	54.89	28.01	26.88
	45,736	74,865	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
Coal	26,327	32,788	856	374	482	26.11	11.41	14.70
Gas	3,875	4,718	291	145	146	61.68	30.73	30.95
Renewables	2,162	8,590	167	6	161	19.44	0.70	18.74
Total Western Canada	32,364	46,096	1,314	525	789	28.51	11.39	17.12
Gas	3,290	7,194	501	351	150	69.64	48.79	20.85
Total Eastern Canada	3,290	7,194	501	351	150	69.64	48.79	20.85
Coal	8,753	12,327	756	467	289	61.33	37.88	23.45
Gas	3,152	6,861	298	111	187	43.43	16.18	27.25
Renewables	1,332	1,491	136	39	97	91.21	26.16	65.05
Total 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

Western Canada

Our Western Canada assets consist of four coal plants, three natural gas-fired facilities, 20 hydro facilities, 12 wind farms, and one biomass facility with a total gross generating capacity of 5,384 MW (5,098 MW net ownership interest). In 2010, we decommissioned our 279 MW Wabamun plant and also began commercial operations at Ardenville, a 69 MW wind farm, and Summerview 2, a 66 MW wind farm. We are currently constructing Keephills 3, a 450 MW (225 MW net ownership interest) merchant coal plant, 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 plant, which are scheduled to be completed by the fourth quarter of 2012. We are also currently constructing Bone Creek, a hydro facility in British Columbia, which will have a generating capacity of 19 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 Genesee 3 plant, a portion of Poplar Creek and Castle River, four hydro facilities, and 11 additional wind farms 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.

McBride Lake, Meridian, Fort Saskatchewan, three hydro facilities, and a significant portion of Poplar Creek and Castle River 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, 2010, production increased 1,069 GWh compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant, lower planned outages at our Keephills plant, and higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro, partially offset by the decommissioning of Wabamun.

In 2009, production decreased 1,921 GWh due to higher planned and unplanned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, lower PPA customer demand, and lower hydro volumes, partially offset by lower planned and unplanned outages at Genesee 3, lower unplanned outages at Keephills, and higher wind volumes due to the acquisition of Canadian Hydro.

Gross margin for the year ended Dec. 31, 2010 increased $19 million ($0.07 per installed MWh) compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant, higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, and lower planned outages at our Keephills plant, partially offset by unfavourable pricing and the decommissioning of Wabamun.

In 2009, gross margin decreased $42 million ($1.00 per installed MWh) due to higher planned outages at our Sundance and Wabamun plants, higher planned outages at Keephills, and lower hydro volumes and prices, partially offset by lower planned and unplanned outages at Genesee 3, lower unplanned outages at Keephills, an adjustment to prior period indices, lower penalties due to lower spot prices, and higher wind volumes due to the acquisition of Canadian Hydro.

Eastern Canada

In 2010, we began commercial operations at Kent Hills 2, a 54 MW expansion of our Kent Hills wind farm in New Brunswick. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations.

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 1,410 MW (1,263 MW net ownership interest). All of our assets 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, 2010, production increased 1,317 GWh compared to the same period in 2009 due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, and market conditions at our natural gas-fired facilities.

In 2009, production increased 539 GWh primarily due to higher wind and hydro volumes as a result of the acquisition of Canadian Hydro and the commissioning of Kent Hills.

For the years ended Dec. 31, 2010 and 2009, gross margin increased $108 million ($1.32 per installed MWh) and $53 million ($3.74 per installed MWh), respectively, due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, and market conditions at our natural gas-fired facilities.

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, 2010, production increased 492 GWh compared to the same period in 2009 primarily due to lower unplanned outages and lower economic dispatching at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal and the expiration of our long-term contract at Saranac in the second quarter of 2009.

In 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.

For the year ended Dec. 31, 2010, gross margins decreased $46 million ($2.27 per installed MWh) compared to the same period in 2009 primarily due to the expiration of the long-term contract at Saranac and unfavourable foreign exchange rates, partially offset by favourable mark-to-market movements and favourable pricing primarily related to purchased power.

In 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.

During the fourth quarter of 2010, unrealized pre-tax gains of $43 million were recorded in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

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, resulting in lower production and gross margin for the year ended Dec. 31, 2010. As a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. The net pre-tax earnings impact of the expiration of this contract is a decrease of approximately $10 million for the year ended Dec. 31, 2010.

Operations, Maintenance, and Administration

For the year ended Dec. 31, OM&A expenses decreased compared to the same period in 2009 due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010 and the acquisition of Canadian Hydro.

In 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.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed:

Year ended Dec. 31	2010	2009	2008
Capitalized	**127**	115	125
Expensed	**70**	118	68
	197	233	193
GWh lost	**2,739**	3,732	3,478

For the year ended Dec. 31, 2010, total planned maintenance costs decreased $36 million compared to the same period in 2009 due to lower planned outages across the fleet. In 2010, production lost as a result of planned maintenance decreased 993 GWh compared to the same period in 2009 primarily due to lower planned outages at our Sundance plant and Centralia Thermal.

In 2009, total planned maintenance costs increased $40 million due to higher planned outages across the fleet and cost escalations. Production lost as a result of planned maintenance increased by 254 GWh primarily due to the uprate on Unit 5 at our Sundance plant.

Depreciation Expense

For the year ended Dec. 31, 2010, depreciation expense decreased compared to the same period in 2009 due to a change in the estimated useful lives of certain coal generation facilities and mining assets, a reduction in the estimated costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

In 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.

Asset Impairment Charges

During the fourth quarter of 2010, we completed our annual comprehensive impairment assessment based on fair value estimates derived from our long-range forecast and market values evidenced in the marketplace. As a result, we recorded pre-tax asset impairment charges of $89 million ($79 million after deducting the amount that is attributable to the non-controlling interest) on certain Generation assets, comprised of a $65 million charge against our natural gas fleet and a $24 million charge against our coal fleet. The natural gas fleet impairment reflects lower forecast pricing at one of our merchant facilities and the pending sale of our 50 per cent interest in our Meridian facility, which had no impact to consolidated earnings as the impairment was attributable to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at our Sundance facility and primarily reflects our shift in 2010 to managing our coal-fired generation facilities on a unit pair basis, resulting in the impairment assessment now being performed on a unit pair basis.

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 Westfield site was placed on hold indefinitely and in 2009, the costs that had been capitalized were expensed.

ENERGY TRADING: 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 Energy Trading's activities.

Energy Trading 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 and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results 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 Energy Trading is allocated to the Generation segment based on an estimate of operating expenses and a percentage of resources dedicated to providing support and analysis. This fixed fee intersegment allocation is represented as a cost recovery in Energy Trading and an operating expense within Generation. During 2010, certain support costs previously borne by the Energy Trading segment and recovered through the intersegment fee started being directly charged to the Generation segment.

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

Year ended Dec. 31	2010	2009	2008
Gross margin	**41**	47	105
Operations, maintenance, and administration	**17**	31	53
Depreciation and amortization	**2**	4	3
Intersegment cost allocation	**(5)**	(32)	(30)
Operating expenses	**14**	3	26
Operating income	**27**	44	79

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased compared to the same period in 2009 primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

In 2009, Energy Trading 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.

For the year ended Dec. 31, 2010, OM&A costs and the intersegment fee decreased compared to the same period in 2009 as a result of the change in how we record certain support costs between the Energy Trading and Generation segments, as described above.

For the year ended Dec. 31, 2009, OM&A expenses decreased due to a reduction in both discretionary expenditures and staff compensation costs. The intersegment fee in 2009 was comparable to 2008.

CORPORATE: Our Generation and Energy Trading business 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.

The expenses incurred by the Corporate segment are as follows:

Year ended Dec. 31	2010	2009	2008
Operations, maintenance, and administration	**68**	86	97
Depreciation and amortization	**19**	18	16
Operating expenses	**87**	104	113

OM&A costs for the year ended Dec. 31, 2010 decreased compared to the same period in 2009 primarily due to information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010.

In 2009, OM&A costs decreased primarily due to a reduction in staff compensation costs.

Net Interest Expense

Year ended Dec. 31	2010	2009	2008
Interest on debt	**243**	183	177
Capitalized interest	**(48)**	(36)	(21)
Interest income from the resolution of certain outstanding tax matters	**(14)**	–	(30)
Interest income	**(3)**	(6)	(16)
Other	**–**	3	–
Net interest expense	**178**	144	110

Net interest expense for the year ended Dec. 31, 2010 increased compared to the same period in 2009 due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

In 2009, net interest expense increased 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.

Other Income

In 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. The sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

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 150 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 we do not own. 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, 2010 decreased compared to the same period in 2009 due to lower earnings at CE Gen as a result of the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TA Cogen.

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.

Income Taxes

Our income tax rates and tax expense are based on the earnings generated in each jurisdiction in which we operate and any permanent differences between how pre-tax income is calculated for accounting and tax purposes. If there is a timing difference between when an expense or revenue item is recognized for accounting and tax purposes, these differences result in future income tax assets or liabilities and are measured using the income tax rate expected to be in effect when these temporary differences reverse. The impact of any changes in future income tax rates on future income tax assets or liabilities is recognized in earnings in the period the new rates are substantively enacted.

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

Year ended Dec. 31	2010	2009	2008
Earnings before income taxes	**220**	196	258
Asset impairment charges	**79**	16	–
Unrealized gains related to ineffectiveness in certain power hedging relationships	**(43)**	–	–
Settlement of commercial issue	**–**	(7)	–
Change in life of Centralia parts	**–**	2	18
Gain on sale of assets at Centralia	**–**	–	(6)
Writedown of Mexican equity investment	**–**	–	97
Comparable earnings[1] before income taxes	**256**	207	367
Income tax expense	**1**	15	23
Income tax recovery on asset impairment charges	**25**	6	–
Income tax expense related to ineffectiveness in certain power hedging relationships	**(15)**	–	–
Income tax recovery related to the resolution of certain outstanding tax matters	**30**	–	–
Income tax expense on settlement of commercial issue	**–**	(1)	–
Income tax recovery on change in life of Centralia parts	**–**	1	6
Income tax recovery related to change in future tax rates	**–**	5	–
Income tax expense on gain on sale of assets at Centralia	**–**	–	(2)
Income tax recovery recorded on the sale of our Mexican equity investment	**–**	–	35
Income tax recovery related to tax positions	**–**	–	15
Income tax expense excluding non-comparable items	**41**	26	77
Effective tax rate on comparable earnings before income taxes (%)	**16**	13	21

1 *Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of this item, as well as a reconciliation to net earnings.*

Income tax expense excluding non-comparable items increased for the year ended Dec. 31, 2010 compared to the same period in 2009 as a result of higher comparable earnings before income taxes.

In 2009, the income tax expense excluding non-comparable items 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 tax recovery related to tax positions recorded in 2008.

The effective tax rate increased for the year ended Dec. 31, 2010 and decreased for the year ended Dec. 31, 2009 primarily due to certain deductions that do not fluctuate with earnings and a change in the mix of jurisdictions where pre-tax income is earned.

Financial Position

The following chart outlines significant changes in the Consolidated Balance Sheets from Dec. 31, 2009 to Dec. 31, 2010:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	**(24)**	Improved cash management
Income taxes receivable	**(20)**	Recovery of tax prepayments and overpayments
Inventory	**(37)**	Higher production at coal facilities
Long-term receivable	**(49)**	Resolution of certain outstanding tax matters
Risk management assets (current and long-term)	**105**	Price movements
Property, plant, and equipment, net	**18**	Capital additions, partially offset by depreciation, the Canadian Hydro purchase price allocation adjustment, asset impairment, and foreign exchange
Assets held for sale	**60**	Meridian assets
Goodwill	**83**	Canadian Hydro purchase price allocation adjustment
Intangible assets	**(40)**	Canadian Hydro purchase price allocation adjustment and amortization expense
Accounts payable and accrued liabilities	**(18)**	Timing of payments, combined with lower operational expenditures
Collateral received	**40**	Collateral collected from counterparties as a result of a change in forward prices
Dividends payable	**69**	Timing of Q1 2011 quarterly cash dividend declaration
Long-term debt (including current portion)	**(208)**	Repayment of long-term debt, partially offset by the issuance of U.S.$300 million senior notes
Risk management liabilities (current and long-term)	**35**	Price movements
Asset retirement obligation (including current portion)	**(40)**	Revised cost estimate of the decommissioning of our Wabamun plant and foreign exchange
Deferred credits and other long-term liabilities	**22**	Timing of deferred revenues and commitments
Non-controlling interests	**(43)**	Distributions and hedging losses in excess of earnings attributable to non-controlling interest and increased investment in Kent Hills
Shareholders' equity	**248**	Issuance of preferred 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 Energy Trading 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 fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are 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 Comprehensive Income. When these contracts are settled, the value previously recorded in Other Comprehensive Income ("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. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI, as discussed above, while any ineffective portion is recognized in net earnings.

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.

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

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

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

1 Option contracts may require an upfront cash investment.

Cash Flow Hedges

Cash flow hedges are categorized as project or commodity hedges and are used to offset foreign exchange and commodity price exposures on long-term projects as a result of market fluctuations. These contracts have a maximum duration of five years.

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[1]	–	–	–	–
Reporting date (marked-to-market)[2]	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓

1 Option contracts may require an upfront cash investment.
2 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.

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

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

1 Option contracts may require an upfront cash investment.
2 Any ineffective portion is recorded in the Consolidated Statements of Earnings.

During the year, the change in the position of financial instruments to a net asset position is primarily a result of changes in future prices on contracts in our Generation segment. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding fair valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2009.

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 reasonable possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2010, Level III instruments had a net liability carrying value of $20 million.

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.

Foreign exchange gains or losses related to net investment hedges are recorded in OCI until there is a permanent reduction in the net investment of the foreign operation. If there is a permanent reduction in the net investment of the foreign operation, the foreign exchange gains or losses previously recorded in OCI are transferred to net earnings in that period.

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

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

Non-Hedges

We use natural hedges as much as possible, such as U.S. interest rates on our U.S. denominated long-term debt, to offset any exposures related to changes in foreign exchange rates. Financial instruments not designated as hedges are used to reduce currency risk on the results of our foreign operations due to the fluctuation of exchange rates beyond what is naturally hedged. All gains or losses related to non-hedges are recorded in the Consolidated Statements of Earnings as they either do not qualify for, or have not been designated for, hedge accounting.

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

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

1 *Some contracts may require an initial cash investment.*

Employee Share Ownership

We employ a variety of stock-based compensation plans to align employee and corporate objectives.

Under the terms of our Stock Option Plans, employees below manager level receive grants that vest in equal installments over four years, and expire after 10 years. The conversion of these options does not materially affect the calculation of the total weighted average number of common shares outstanding.

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 for employees below vice president level, and for two additional years for employees at the vice president level and above. The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding.

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, 2010, accounts receivable from employees under the plan totalled $2 million (2009 – $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 for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2010.

We provide other health and dental benefits to the age of 65 for both disabled members and retired members (other post-retirement benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2010.

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 $62 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 years ended Dec. 31, 2010 and 2009:

Year ended Dec. 31	**2010**	2009	Explanation of change
Cash and cash equivalents, beginning of year	**82**	50	
Provided by (used in):			
Operating activities	**811**	580	Higher cash earnings of $54 million and favourable changes in working capital of $177 million due to the timing of operational payments, favourable inventory movements, and the timing of certain tax-related recoveries.
Investing activities	**(720)**	(1,598)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million in 2009 and a decrease in 2010 capital spending of $114 million, partially offset by a decrease in collateral received from counterparties of $40 million.
Financing activities	**(113)**	1,053	Increase of $818 million in proceeds from the issuance of long-term debt and $397 million from the issuance of common shares in 2009, and a net increase in the repayment of debt of $255 million, partially offset by proceeds of $291 million from the issuance of preferred shares in 2010.
Translation of foreign currency cash	**(2)**	(3)	
Cash and cash equivalents, end of year	**58**	82	

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 the issuance of long-term debt of $617 million, increase in proceeds from the 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	

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 or equity 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 $4.2 billion at Dec. 31, 2010 compared to $4.4 billion at Dec. 31, 2009. Total long-term debt decreased from Dec. 31, 2009 primarily due to the issuance of preferred shares and favourable foreign exchange movements, partially offset by growth capital expenditures.

Credit Facilities

At Dec. 31, 2010, we had a total of $2.0 billion (2009 – $2.1 billion) of committed credit facilities of which $1.1 billion (2009 – $0.7 billion) is not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2010, the $0.9 billion (2009 – $1.4 billion) of credit utilized under these facilities is comprised of actual drawings of $0.6 billion (2009 – $1.1 billion) and of letters of credit of $0.3 billion (2009 – $0.3 billion). 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 that mature between the fourth quarter of 2012 and the third quarter of 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $1.1 billion available under the credit facilities, we also have $58 million of cash.

Share Capital

At Dec. 31, 2010, we had 220.3 million (2009 – 218.4 million) common shares issued and outstanding. During the year ended Dec. 31, 2010, 1.9 million (2009 – 20.8 million) common shares were issued for $42 million (2009 – $408 million), of which $37 million (2009 – nil) was issued under the terms of the DRASP plan.

During the year ended and as at Dec. 31, 2010, 12.0 million (2009 – nil) first preferred shares were issued for $239 million (2009 – nil).

On Feb. 23, 2011, we had 221.2 million common shares and 12.0 million first preferred shares outstanding.

NCIB Program

For the year ended Dec. 31, 2010, no shares were acquired or cancelled under the NCIB program prior to its expiry on May 6, 2010. In 2009, no shares were acquired or cancelled 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, energy trading activities, hedging activities, and purchase obligations. At Dec. 31, 2010, we provided letters of credit totalling $297 million (2009 – $334 million) and cash collateral of $27 million (2009 – $27 million). 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, 2010, the excess of current liabilities over current assets is $246 million (2009 – $10 million). The excess of current liabilities over current assets increased $236 million compared to 2009 due to an increase in the current portion of long-term debt and a decrease in collateral received from counterparties, partially offset by an increase in net risk management assets, lower operational expenditures and the timing of related payments, favourable inventory movements, and the timing of certain tax recoveries.

Capital Structure

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

	2010		2009	
As at Dec. 31	**Amount**	**%**	Amount	%
Debt, net of cash and cash equivalents	**4,177**	**54**	4,360	56
Non-controlling interests	**435**	**6**	478	6
Shareholders' equity	**3,177**	**41**	2,929	38
Total capital	**7,789**	**100**	7,767	100

Commitments

Contractual repayments of 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
2011	8	1	14	55	19	253	237	106	693
2012	8	6	13	55	18	674	214	36	1,024
2013	9	7	12	55	17	629	194	–	923
2014	8	7	11	55	17	231	157	–	486
2015	8	7	10	60	9	681	127	–	902
2016 and thereafter	22	12	52	320	3	1,769	960	–	3,138
Total	**63**	**40**	**112**	**600**	**83**	**4,237**	**1,889**	**142**	**7,166**

1 Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature between the fourth quarter of 2012 and the third quarter of 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

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind and hydro, we also believe that coal and natural gas as fuels will continue to play an important role in meeting future energy needs. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low cost electricity.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our business.

Canada

On June 23, 2010, the Government of Canada announced plans to regulate GHG emissions from the coal-fired power sector. The proposal, if passed into law, would become effective in 2015 and require existing coal-fired plants to meet a natural gas emissions performance standard by their 45th year of operation, or the end of their PPA term, whichever is later. If the plants subject to the regulation do not meet the required performance standard by that time, they would be required to cease operations. Until then, the plants would not be subject to any federal GHG compliance costs.

The federal government continues with the drafting of the above regulations, and has stated its intention to release draft regulations by April 2011. The draft regulations would then be subject to consultations with provinces, industry, and the public. We are in discussions with both the Governments of Canada and Alberta about the design of the proposed regulation.

The above development would provide regulatory clarity for future capital decision-making. There are some issues that will have to be resolved, including how transition costs are recovered by generators, standards for emission requirements for natural gas-fired facilities, and how CCS will continue to be supported. The effect of this proposal on the Alberta deregulated market and PPA structure must also be considered.

Additionally, work has continued on the development of a national Clean Air Management System ("CAMS") for air pollutants. Development work is being done through collective efforts of federal and provincial governments, industry, and environmental organizations, with the goal of constructing an acceptable national structure for managing pollutants such as sulphur dioxide ("SO_2"), nitrogen oxide ("NOx") and particulates. Conceptually the system would establish baseline ambient air quality standards, industry emission standards, and mechanisms to address areas of non-compliance. It is expected that the CAMS model would default to provincial jurisdiction unless air quality problems remain unresolved. This process is expected to take several more years to complete. We are involved in the working groups. The impact of CAMS on our operations, if implemented, is not evident at this time.

In Ontario, the provincial government continues to develop its plans for a GHG regulatory framework consistent with the Western Climate Initiative ("WCI") model. The WCI model is a cap and trade design being developed jointly between several Canadian provinces and U.S. states, including California, to establish similar reduction targets and a common emissions trading market. Details of the Government of Ontario's proposed design have not yet been released.

In Alberta, mercury capture technology was installed by the end of the year and began operating at our coal-fired plants in order to achieve compliance with the Alberta requirement to reduce mercury emissions by 70 per cent by Jan. 1, 2011. To date, the mercury reduction requirements at these plants have been met.

In British Columbia, the provincial government is in the process of developing regulations for emissions trading and an offsets system under the *Greenhouse Gas Reduction (Cap and Trade) Act*. The system would be compatible with the WCI model. Consultations are underway regarding its design, with finalization of the regulations expected in 2011. Given our low-carbon operations in British Columbia, this regulatory initiative is not expected to have any material impact on the Corporation.

United States

In the absence of legislative action, the administration is moving to regulate greenhouse gases under the *Clean Air Act*. Under the "tailoring rule" adopted in 2010, on July 1, 2011, the Environmental Protection Agency ("EPA") will require new plants, or major modifications to existing plants, to acquire permits for GHGs. After that point, new or modified plants that otherwise would trigger major source preconstruction permit thresholds would be required to employ best available technology to reduce their GHG emissions. The EPA began implementing these rules on Jan. 2, 2011. The definition of best available technology has not yet been determined. This EPA regulation is expected to face legal challenges as well as some opposition from Congress, and may be subject to further refinement in other rulemakings.

Further, at the end of December in 2010, the EPA stated its intentions to implement New Source Performance Standards for GHGs for power plants and refineries. These proposed regulations would cover emissions from both new and existing sources, and are expected to be completed by the end of 2012. The EPA does not expect existing sources would be affected until 2015 or 2016. These proposed regulations have not yet been developed so their impact is unclear. Again, this initiative is expected to face legal hurdles.

In Washington, we have been working with the state government to develop a plan to reduce GHG emissions from our Centralia Thermal plant, consistent with the Governor's Executive Order to reduce emissions by approximately 50 per cent of current levels by 2025. Discussions with Washington State and other stakeholders are ongoing.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form and within the Risk Management section of this MD&A, many of our activities and properties are subject to environmental requirements, as well as changes in our liabilities under these requirements, which may have a material adverse affect upon our consolidated financial results.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We 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.

In 2010, we estimate that 37 million tonnes of GHGs with an intensity of 0.976 tonnes per MWh (2009 – 36 million tonnes of GHGs with an intensity of 0.980 tonnes per MWh) were emitted as a result of normal operating activities[1]. Increased energy production from our fossil-based assets and the related increase in emissions were partially offset by the decommissioning of Unit 4 at our Wabamun plant, which represents a reduction of approximately two million tonnes per year of GHGs. 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 provides oversight to our environmental management programs and emission reduction initiatives in order to ensure continued compliance with environmental regulations.

Our environmental management programs encompass the following elements:

Renewable Power

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

1 *2010 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.*

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 have installed 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 SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at our Genesee 3 plant.

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 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 funding commitments 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 supports a FEED study that is expected to be completed in 2011. Once built, the prototype plant will be one of the largest integrated CCS power facilities in the world. The project will be designed to capture one megatonne of carbon dioxide ("CO_2") per year from our new 450 MW (225 MW net ownership interest) Keephills 3 coal plant. The CO_2 will be used for enhanced oil recovery as well as injected into a permanent geological storage site. Additionally, on Nov. 28, 2010, Project Pioneer was awarded $5 million from the Global Carbon Capture and Storage Institute to enhance knowledge transfer from the project both nationally and globally.

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.

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 that 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 Centralia Thermal; 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 2010 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.

2011 Outlook

In 2011, we anticipate modest comparable EPS growth based upon the factors that are discussed below.

Business Environment

Power Prices

In 2011, power prices are expected to remain at 2010 levels due to the influence of low natural gas prices. In the Alberta market, the longer-term fundamentals of the market remain positive 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 any recovery of power prices. Natural gas prices are expected to remain low until 2012.

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 greenhouse gas regulatory framework with the U.S., although coal-fired power is being addressed separately and earlier. 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

The economic environment has shown signs of improvement in 2010 and we expect this trend to continue through 2011 at a slow to moderate pace.

We had no counterparty losses in 2010, and 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 2011 due to the start of commercial operations at Keephills 3 and Bone Creek. Overall production is expected to increase in 2011 due to the start of commercial operations at Keephills 3 and Bone Creek, lower planned and unplanned outages, and higher customer demand. Overall fleet availability is expected to be approximately 89 to 90 per cent in 2011 due to lower planned and unplanned outages.

Commodity Hedging
Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis we target being up to 90 per cent contracted for the upcoming year, stepping down to 65 per cent in the fourth year. As at the end of 2010, approximately 88 per cent of our 2011 capacity was contracted. The average price of our short-term physical and financial contracts in 2011 ranges from $65-$70 per MWh in Alberta, and from U.S.$55-$60 per MWh in the Pacific Northwest.

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 2011, on a standard cost basis, are expected to be consistent with 2010.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2011 is expected to be consistent with 2010.

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 could reduce the year to year volatility of prices going forward.

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 for 2011 are expected to be lower as a result of certain planned maintenance costs that had been expensed under Canadian GAAP being capitalized under International Financial Reporting Standards ("IFRS") in 2011, and lower OM&A costs related to our Poplar Creek base plant. In 2011, we will no longer operate the Poplar Creek base plant resulting in reduced OM&A expenditures and associated cost recoveries. The impact of no longer operating the Poplar Creek base plant is not expected to be significant to net earnings.

Energy Trading
Earnings from our Energy Trading 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 2011 objective is for Energy Trading to contribute between $45 million and $65 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 denominated expenses, including interest charges, which largely offset our net foreign denominated revenues.

Net Interest Expense
Net interest expense for 2011 is expected to be higher than 2010 mainly due to higher debt balances, higher variable interest rates, lower capitalized interest, and lower interest income. However, changes in interest rates and in the value of the Canadian dollar relative 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 in the future. To mitigate this liquidity risk, we expect to maintain $2.0 billion of committed credit facilities, and we 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 the contracted prices.

Income Taxes
The effective tax rate for 2011 is expected to be approximately 17 to 22 per cent.

Capital Expenditures

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

Growth Capital Expenditures

In 2010, we spent a total of $470 million on growth capital expenditures, net of any joint venture contributions received. In 2010, we successfully commenced commercial operations at Summerview 2, Ardenville, and Kent Hills 2. We have five additional significant growth capital projects that are currently in progress with targeted completion dates between Q1 2011 and Q4 2012.

A summary of the significant projects that are in progress is outlined below:

	Total Project		2010	2011		
Project	Estimated spend	Spend to date[1]	Actual spend[1]	Estimated spend	Target completion date	Details
Keephills 3	988	928	221	50-60	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Keephills Unit 1 uprate	34	4	3	10-20	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Keephills Unit 2 uprate	34	6	5	20-30	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Bone Creek	48	54	50	–	Q1 2011	A 19 MW hydro facility in British Columbia
Sundance Unit 3 uprate	27	3	3	10-15	Q4 2012	A 15 MW efficiency uprate at our Sundance plant
Total growth expenditures	**1,131**	**995**	**282**	**90-125**		

1 Represents amounts spent as of Dec. 31, 2010. In 2010, we also spent a combined total of $188 million on Summerview 2, Ardenville, and Kent Hills 2.

Amounts disclosed in the above chart are shown net of any joint venture contributions received.

The total estimated spend for Bone Creek is less than the amount incurred to date due to the timing of project spend and estimated recoveries in 2011.

Sustaining Capital Expenditures

Certain costs related to planned maintenance that have been expensed under Canadian GAAP in 2010 will be capitalized under IFRS in 2011. Our estimate for total sustaining capital expenditures in 2011, net of any contributions received, is allocated among the following:

Category	Description	Spend in 2010	Expected cost
Routine capital	Expenditures to maintain our existing generating capacity	147	120-135
Productivity capital	Projects to improve power production efficiency	9	10-20
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	25	25-30
Planned maintenance	Regularly scheduled major maintenance	127	180-210
Total sustaining expenditures		**308**	**335-395**

Details of the 2011 planned maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected cost
Capitalized	105-130	75-80	180-210
Expensed	–	0-5	0-5
	105-130	75-85	175-200

	Coal	Gas and Renewables	Total
GWh lost	1,480-1,490	630-640	2,110-2,130

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing bank 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 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 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, 2010, TAGP had received $61 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.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TA Cogen, which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). 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 two of its plants over the period of the swap. The notional gas volumes in the swap transactions are equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

Risk Management

Our business activities expose us to a 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.

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 review consists 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 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 and 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 and Financial Exposure Management policies and reviews quarterly ERM reporting.

The Exposure Management Committee ("EMC") is chaired by our Chief Financial Officer and is comprised of the Chief Operating Officer, Vice-President Controller and Treasurer, Vice-President Corporate Planning and Analysis, Vice-President Operations Finance, and Vice-President Internal Audit and Risk. The EMC is responsible for reviewing and monitoring compliance within approved financial and commodity exposure management policies.

The Technical Risk and Commercial Team ("TRACT") is a committee chaired by the Vice-President, Engineering, Environment, and Construction Services, 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.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster 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 sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exceptional approval process. Periodic reviews and audits are performed to ensure compliance with these policies.

Reporting

On a regular basis, risk exposures are reported to key decision makers including the Board of Directors, senior management, and the EMC. Reporting to the EMC includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion of actions to minimize risks. 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 Director, 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 chair of the ARC.

Value at Risk and Trading Positions

VaR is the primary measure used to manage our exposure to market risk resulting from energy trading activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR at Dec. 31, 2010 associated with our proprietary energy trading activities was $5 million (2009 – $3 million).

VaR is a commonly used metric that is employed by industry to track the risk in energy trading positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed weekly to measure the financial impact to the trading portfolio resulting from potential market events including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. 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 of changes in certain key variables. The analysis is based on business conditions and production volumes in 2010. 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. For example, the financial performance of our hydro, wind, and geothermal operations are partially dependant upon the availability of their input resources in a given year. 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.

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 required,
- monitoring water resources throughout Alberta and British Columbia to the best of our ability and optimizing this resource against real-time electricity market opportunities, and
- 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.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	24

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse affect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. 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 may be required to 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 availability 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 coverage 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 the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short- and long-term contracts to mitigate 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.

In 2010, we had approximately 95 per cent of production under short-term and long-term contracts and hedges (2009 – 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 the financial exposure to fluctuations in the costs of fuels used in production 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.

In 2010, 81 per cent (2009 – 79 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2009 – 100 per cent) of our purchased coal costs were contractually fixed.

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

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$1.00/MWh	8
Natural gas price	$0.10/GJ	1
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 our coal-fired plants, input costs, such as diesel, tires, the price of mining equipment, the volume of overburden removed to access coal reserves, and the location of mining operations relative to the power plants are some of the exposures in our mining operations. 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 coal 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, 2010, approximately 75 per cent (2009 – 75 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 existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the U.S. 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 management system in place that is designed to continuously improve environmental performance,
- committing significant effort to work with regulators in Canada and the U.S. 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, SO_2, 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 and hydro generation, and
- investing in clean coal technology development, which potentially 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 2010, we spent approximately $55 million (2009 – $45 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.

In October 2010, the Canadian Securities Administrators ("CSA") published guidance on environmental disclosure in Staff Notice 51-333. The guidance directs issuers to address:

- environmental risks and related matters,
- environmental risk oversight and management,
- forward-looking information requirements as they relate to environmental goals and targets, and
- the impact of the adoption of IFRS on disclosure of environmental liabilities.

TransAlta has reviewed this guidance and believe that we comply with these requirements.

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 the creditworthiness of counterparties, contract term limits, and the 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.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2009. We had no counterparty losses in 2010, and 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. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

A summary of our credit exposure for our energy trading operations and hedging activities at Dec. 31, 2010 is provided below:

Counterparty credit rating	Net exposure
Investment grade	349
Non-investment grade	–
No external rating, internally rated as investment grade	26
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 $43 million (2009 – $63 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, the acquisition of equipment and services from foreign suppliers, and our U.S. denominated debt. 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 or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that include:

- 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 such foreign currency exposures. At Dec. 31, 2010, we have hedged approximately 95 per cent (2009 – 97 per cent) of our foreign currency net investment exposure,
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure, and
- entering into forward foreign exchange contracts to hedge future foreign denominated receipts and expenditures, and all U.S. denominated debt outside of our net investment portfolio.

Translation gains and losses related to the carrying value of our foreign operations and any hedges in respect thereof are included in AOCI in shareholders' equity until such a time there is a permanent reduction in our investment.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that a six cent increase or decrease in the U.S. or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.06	3

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for energy 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 energy trading activities on a regular basis to the EMC, senior management, and Board of Directors,
- maintaining investment grade credit ratings, and
- maintaining sufficient undrawn 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 establishing and adhering to policies that include:

- 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, 2010, approximately 25 per cent (2009 – 31 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 five 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 senior management and Board of Directors 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,
- managing 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 2010, 46 per cent (2009 – 46 per cent) of our labour force is covered by 11 (2009 – 11) collective bargaining agreements. In 2010, four (2009 – five) agreements were renegotiated. We anticipate negotiating three agreements in 2011. 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 of those transmission lines are key in our ability to deliver energy produced at our power plants to our customers. However, with the continued growth in demand for electricity coupled with very little transmission capacity being added, and the reduced reliability and available capacity on the existing transmission facilities, the risks associated with the aging existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continue 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 Director, 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 chair of 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, financing costs, 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 comparable earnings before income taxes for 2010 was 16 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 that 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 2010. 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. 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.

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 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.

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

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.

Level III

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

In limited circumstances, we 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 reasonable alternate fundamental price forecasts unavailable.

The effect of using reasonable possible alternative assumptions as inputs to valuation techniques from which the Level III fair values are determined at Dec. 31, 2010 is estimated to be +/- $14 million (2009 – +/- $24 million). 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, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate.

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2010, PP&E makes up 77 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 that 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, retirement costs, and discount rates. In addition, when impairment tests are performed, the estimated useful lives of the plants are reassessed, with any changes 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 2010, pre-tax asset impairment charges of $89 million were recorded related to certain natural gas and coal facilities. Refer to the Asset Impairment section of this MD&A for further details.

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. These estimates are subject to revision in future periods based on new or additional information. 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 2010, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $490 million (2009 – $493 million), of which $42 million (2009 – $40 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.

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, 2010, this goodwill had a total carrying value of $517 million (2009 – $434 million). The change in value from Dec. 31, 2009 is primarily due to the Canadian Hydro purchase price allocation adjustment.

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, 2010. Accordingly, no goodwill impairment charges were recorded for the year ended Dec. 31, 2010.

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 $240 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2010 (2009 – $234 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 $707 million have been recorded on the Consolidated Balance Sheets at Dec. 31, 2010 (2009 – $707 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 consolidated 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 to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

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, 2010, the plan assets had a positive return of $28 million, compared to $38 million in 2009, and a negative return of $55 million in 2008. The 2010 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2009 and 2008.

Asset Retirement Obligation

We recognize AROs 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 AROs. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

At Dec. 31, 2010, the ARO recorded on the Consolidated Balance Sheets was $242 million (2009 – $282 million). We estimate the undiscounted amount of cash flow required to settle the ARO is approximately $0.8 billion, which will be incurred between 2011 and 2072. The majority of these costs will be incurred between 2020 and 2050. The average discount used to calculate the carrying value of the ARO was eight per cent.

Sensitivities for the major assumptions are as follows:

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

Future Accounting Changes

IFRS Convergence

On Jan. 1, 2011, we adopted IFRS for publicly accountable enterprises as required by the Accounting Standards Board. Our project to convert to IFRS consisted 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	Complete
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	Complete

A steering committee continues to monitor the progress of the transition to IFRS and will continue to meet regularly until our March 31, 2011 first interim report under IFRS is completed. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources, and Operations. Quarterly updates are provided to the Audit and Risk Committee.

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 have been addressed as part of our conversion project. Overall, these differences are expected to have a relatively modest impact on our consolidated financial results. The more significant impacts of IFRS to us are as follows:

PP&E

- *Key change in accounting:* Major inspection costs, which are currently expensed, will be capitalized and depreciated over the period until the next major inspection.
- *Income statement impact:* Earnings will likely be less volatile.
- *Balance sheet impact upon transition to IFRS:* Net increase in PP&E of $115 million as previously expensed major inspection costs will be capitalized.
- *Cash flow statement impact:* Major inspection costs will be recorded as cash flows used in investing activities instead of as cash flows used in operating activities.
- *Other differences:* Additional disclosures reconciling the changes in cost and accumulated depreciation for individual classes of PP&E will be required.

Employee Benefits

- *Key change in accounting:* All actuarial gains and losses related to defined benefit plans will be recognized in other comprehensive income.
- *Income statement impact:* Expenses associated with defined benefit plans will differ. The impact on net earnings is not expected to be significant.
- *Balance sheet impact upon transition to IFRS:* Recognition of net cumulative actuarial losses of $78 million (after-tax) in opening retained earnings.
- *Cash flow statement impact:* None.

Joint Arrangements

- *Key change in accounting:* Interests in joint ventures classified as jointly controlled entities can be recognized using either the proportionate consolidation or equity method. We have chosen to account for these entities using the equity method instead of the proportional consolidation method as required by Canadian GAAP. Prior to March 31, 2011, the International Accounting Standards Board is expected to issue a new standard on the accounting for joint ventures that eliminates the option of proportionate consolidation. The new standard is expected to come into effect Jan. 1, 2013, with early adoption permitted. If we decide to early adopt this new standard effective Jan. 1, 2011, no additional changes are expected.
- *Income statement impact:* Revenues and expenses will be recorded as equity earnings or loss, a single line item on the Consolidated Statement of Earnings. There is no impact on net earnings.
- *Balance sheet impact upon transition to IFRS:* Our share of assets and liabilities will be removed from the various line items on the Statement of Financial Position and the corresponding net amount of $202 million will be recorded as an investment.
- *Cash flow statement impact:* Our proportionate share of cash from equity accounted joint ventures will not be reflected on the Consolidated Statement of Cash Flow. Only contributions to and distributions from investments accounted for using the equity method will be reflected in the cash flow statement as an investing activity.

Provisions, Contingent Liabilities, and Contingent Assets

- *Key change in accounting:* AROs are revalued at the end of each quarterly and annual reporting period using current market-based interest rates instead of using historic rates.
- *Income statement impact:* Accretion expense will be classified as a finance (interest) cost under IFRS as opposed to an operating expense under Canadian GAAP, and may fluctuate more often due to the impact of the period-end revaluations.
- *Balance sheet impact upon transition to IFRS:* Due to differences in discount rates, the opening balance of the provisions for ARO will increase by $34 million.
- *Cash flow statement impact:* None.

Arrangements Containing a Lease

- *Key change in accounting:* All contractual arrangements will be evaluated to determine if they contain a finance or operating lease.
- *Income statement impact:* For those contracts that are determined to be finance leases, a portion of payments received under the contract will be recorded as finance (interest) income. For those contracts that are determined to be operating leases, the timing of recognition of revenue may differ. The impact on net earnings in either case is not expected to be significant.
- *Balance sheet impact upon transition to IFRS:* For certain long-term contracts that are deemed to be finance leases, the associated PP&E of $30 million will be removed from the Consolidated Balance Sheets and replaced with a long-term receivable of $50 million, representing the present value of lease payments to be received over the life of the contract.
- *Cash flow statement impact:* Payments received under the contract for finance leases will be recorded as cash flows from financing activities instead of cash flows from operating activities.

Asset Impairment

- *Key change in accounting:* Asset impairment testing no longer utilizes undiscounted future cash flows to initially assess for impairment. Instead, an asset's carried amount is compared to the greater of its value in use or fair value less normal costs to sell. Asset impairment charges can be reversed if the conditions creating the impairment reverse.
- *Income statement impact:* Depreciation expense for any impaired assets will be lower over the useful life of the asset.
- *Balance sheet impact upon transition to IFRS:* Impairment charges of $98 million will reduce PP&E, opening retained earnings, and non-controlling interests, as well as increase provisions.
- *Cash flow statement impact:* None.

A number of elections were available to us under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* that assisted with our transition to IFRS. We have made use of several of these elections as follows:

- Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax, of $63 million, will be reset to zero;
- Share-based payment guidance under IFRS will only be applied to equity instruments outstanding at transition that were granted on or after Nov. 7, 2002, and which had not vested by the transition date;
- Business combinations that occurred prior to Jan. 1, 2010 will continue to be measured and recorded at the Canadian GAAP amounts;
- We will use a simplified method to recalculate the cost of decommissioning assets included in PP&E; and
- We will not adjust interest previously capitalized as part of PP&E under Canadian GAAP.

In addition, various presentation changes are required under IFRS that have no impact on opening retained earnings.

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 applicable to common shares below:

Year ended Dec. 31	2010	2009	2008
Revenues	**2,819**	2,770	3,110
Fuel and purchased power	**1,202**	1,228	1,493
Gross margin	**1,617**	1,542	1,617
Operations, maintenance, and administration	**634**	667	637
Depreciation and amortization	**459**	475	428
Taxes, other than income taxes	**27**	22	19
Operating expenses	**1,120**	1,164	1,084
Operating income	**497**	378	533
Foreign exchange gain (loss)	**10**	8	(12)
Asset impairment charges	**(89)**	(16)	–
Net interest expense	**(178)**	(144)	(110)
Other income	**–**	8	5
Equity loss	**–**	–	(97)
Earnings before non-controlling interests and income taxes	**240**	234	319
Non-controlling interests	**20**	38	61
Earnings before income taxes	**220**	196	258
Income tax expense	**1**	15	23
Net earnings	**219**	181	235
Preferred share dividends	**1**	–	–
Net earnings applicable to common shares	**218**	181	235

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 results from prior periods. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the year.

In calculating comparable earnings for 2010, we excluded asset impairment charges, as well as unrealized gains related to certain power hedging relationships deemed ineffective for accounting purposes, as these transactions are unusual in nature and have not historically been a normal occurrence in the course of operating our business. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in comparable earnings in the period that they settle, the majority of which will settle during the second quarter of 2011. In addition, we excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

In calculating comparable earnings for 2009, we have excluded asset impairment charges, 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 2009 and 2008, the change in life of certain component parts at Centralia Thermal was excluded from the calculation of comparable earnings as it relates to the cessation of mining activities at the Centralia coal mine and conversion to consuming solely third-party supplied coal.

In calculating comparable earnings for 2008, we excluded the impact recoveries related to certain tax positions 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 as we do not normally dispose of large quantities of fixed assets. We have also excluded the writedown of our Mexican equity investment.

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

Year ended Dec. 31	2010	2009	2008
Net earnings applicable to common shares	**218**	181	235
Asset impairment charges, net of tax	**54**	10	–
Unrealized gains related to ineffectiveness in certain power hedging relationships, net of tax	**(28)**	–	–
Income tax recovery related to the resolution of certain outstanding tax matters	**(30)**	–	–
Gain on sale of assets at Centralia, net of tax	**–**	–	(4)
Change in life of Centralia parts, net of tax	**–**	1	(12)
Settlement of commercial issue, net of tax	**–**	(6)	–
Tax rate change	**–**	(5)	–
Recovery related to tax positions	**–**	–	(15)
Writedown of Mexican equity investment, net of tax	**–**	–	62
Earnings on a comparable basis	**214**	181	290
Weighted average number of common shares outstanding in the year	**219**	201	199
Earnings on a comparable basis per share	**0.98**	0.90	1.46

Comparable EBITDA

Presenting comparable 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	2010	2009	2008
Operating income	**497**	378	533
Asset retirement obligation accretion per the Consolidated Statements of Cash Flows	**21**	24	22
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**490**	493	451
EBITDA	**1,008**	895	1,006
Unrealized gains related to ineffectiveness in certain power hedging relationships, pre-tax	**(43)**	–	–
Settlement of commercial issue, pre-tax	**–**	(7)	–
Comparable EBITDA	**965**	888	1,006

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

Funds from Operations and Cash Flow from Operating Activities per Share

Presenting funds from operations and cash flow from operating activities from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before and after changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with prior periods. Cash flow from operating activities per share is calculated using the weighted average common shares outstanding during the period.

	2010	2009	2008
Funds from operations	**783**	729	828
Change in non-cash operating working capital balances	**28**	(149)	210
Cash flow from operating activities	**811**	580	1,038
Weighted average number of common shares outstanding in the year	**219**	201	199
Cash flow from operating activities per share	**3.70**	2.89	5.22

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, 2010, represents total additions to PP&E per the Consolidated Statements of Cash Flows less $482 million ($470 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2009, we invested $524 million ($510 million net of joint venture contributions). In 2008, we invested $541 million ($515 million net of joint venture contributions).

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

Year ended Dec. 31	2010	2009	2008
Cash flow from operating activities	**811**	580	1,038
Add (deduct):			
Sustaining capital expenditures	**(308)**	(380)	(465)
Cash dividends paid on common shares	**(216)**	(226)	(212)
Distribution to subsidiaries' non-controlling interests	**(62)**	(58)	(98)
Non-recourse debt repayments[1]	**(21)**	(25)	(28)
Other income	**-**	(8)	-
Timing of contractually scheduled payments	**-**	-	(116)
Cash flows from equity investments	**-**	-	2
Free cash flow (deficiency)	**204**	(117)	121

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.

Comparable ROCE

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 ROCE is presented below:

Year ended Dec. 31	2010	2009	2008
Earnings before income taxes per the Consolidated Statements of Earnings	**220**	196	258
Net interest expense	**178**	144	110
Non-controlling interests	**20**	38	61
Non-comparable items			
Asset impairment charges, pre-tax	**89**	16	-
Unrealized gains related to ineffectiveness in certain power hedging relationships, pre-tax	**(43)**	-	-
Change in life of Centralia parts, pre-tax	**-**	2	18
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)
Comparable earnings before net interest expense, non-controlling interests, and income taxes	**464**	389	538
Average invested capital excluding AOCI	**7,645**	6,659	5,588
Comparable ROCE	**6.1**	5.8	9.6

Selected Quarterly Information

	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Revenues	**726**	**582**	**700**	**811**
Net earnings applicable to common shares	**67**	**51**	**38**	**62**
Basic and diluted earnings per common share	**0.31**	**0.23**	**0.17**	**0.28**
Comparable earnings per common share	**0.31**	**0.10**	**0.17**	**0.40**

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Revenues	756	585	666	763
Net earnings (loss) applicable to common shares	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

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 (loss) 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.

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, 2010, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

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 responsibilities 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

Brett Gellner
Chief Financial Officer

February 23, 2011

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 proportionately consolidates the accounts of the Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures 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 2010 consolidated financial statements of TransAlta Corporation included $1,454 million and $804 million of total and net assets, respectively, as of Dec. 31, 2010, and $344 million and $64 million of revenues and net earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at Dec. 31, 2010, 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, 2010, 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

Brett Gellner
Chief Financial Officer

February 23, 2011

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, 2010, 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 Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures, which are included in the 2010 consolidated financial statements of the Corporation and constituted $1,454 million and $804 million of total and net assets, respectively, as of December 31, 2010, and $344 million and $64 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness, CE Generation, Wailuku, and Genesee 3 joint ventures.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAlta Corporation as of December 31, 2010 and 2009 and the related 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, 2010, and our report dated February 23, 2011, expressed an unqualified opinion thereon.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2011

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, 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, 2010, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated 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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2011 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst + Young LLP

Ernst & Young LLP
Chartered Accountants

Calgary, Canada
February 23, 2011

Consolidated Statements of Earnings and Retained Earnings

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2010**	2009	2008
Revenues	**2,819**	2,770	3,110
Fuel and purchased power	**1,202**	1,228	1,493
	1,617	1,542	1,617
Operations, maintenance, and administration	**634**	667	637
Depreciation and amortization	**459**	475	428
Taxes, other than income taxes	**27**	22	19
	1,120	1,164	1,084
	497	378	533
Foreign exchange gain (loss) *(Note 8)*	**10**	8	(12)
Asset impairment charges *(Note 3)*	**(89)**	(16)	–
Net interest expense *(Notes 8 and 17)*	**(178)**	(144)	(110)
Equity loss *(Note 24)*	**–**	–	(97)
Other income *(Note 4)*	**–**	8	5
Earnings before non-controlling interests and income taxes	**240**	234	319
Non-controlling interests *(Note 5)*	**20**	38	61
Earnings before income taxes	**220**	196	258
Income tax expense *(Note 6)*	**1**	15	23
Net earnings	**219**	181	235
Preferred share dividends *(Note 21)*	**1**	–	–
Net earnings applicable to common shares	**218**	181	235
Retained earnings			
Opening balance	**634**	688	763
Common share dividends *(Note 20)*	**(319)**	(235)	(215)
Shares cancelled under NCIB *(Note 20)*	**–**	–	(95)
Closing balance	**533**	634	688
Weighted average number of common shares outstanding in the year	**219**	201	199
Net earnings per common share, basic and diluted *(Note 20)*	**1.00**	0.90	1.18

See accompanying notes.

Consolidated Balance Sheets

Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009
		(Note 2)
Cash and cash equivalents *(Notes 7 and 24)*	**58**	82
Accounts receivable *(Notes 7, 9, 24, and 28)*	**428**	421
Collateral paid *(Notes 7 and 8)*	**27**	27
Prepaid expenses *(Note 24)*	**10**	18
Risk management assets *(Notes 7 and 8)*	**265**	144
Income taxes receivable	**19**	39
Inventory *(Note 10)*	**53**	90
	860	821
Long-term receivable *(Notes 7 and 11)*	**–**	49
Property, plant, and equipment *(Notes 12, 24, and 29)*		
Cost	**11,706**	11,701
Accumulated depreciation	**(4,129)**	(4,142)
	7,577	7,559
Assets held for sale *(Note 13)*	**60**	–
Goodwill *(Notes 14, 24, and 29)*	**517**	434
Intangible assets *(Notes 15 and 24)*	**304**	344
Future income tax assets *(Note 6)*	**240**	234
Risk management assets *(Notes 7 and 8)*	**208**	224
Other assets *(Notes 16 and 24)*	**127**	121
Total assets	**9,893**	9,786
Short-term debt *(Note 7)*	**1**	–
Accounts payable and accrued liabilities *(Notes 7 and 24)*	**503**	521
Collateral received *(Notes 7 and 8)*	**126**	86
Risk management liabilities *(Notes 7, 8, and 24)*	**35**	45
Income taxes payable	**8**	10
Future income tax liabilities *(Note 6)*	**77**	45
Dividends payable *(Note 7)*	**130**	61
Current portion of long-term debt – recourse *(Notes 7 and 17)*	**235**	7
Current portion of long-term debt – non-recourse *(Notes 7 and 17)*	**20**	24
Current portion of asset retirement obligation *(Note 18)*	**38**	32
	1,173	831
Long-term debt – recourse *(Notes 7 and 17)*	**3,450**	3,857
Long-term debt – non-recourse *(Notes 7, 17, and 24)*	**529**	554
Asset retirement obligation *(Notes 18 and 24)*	**204**	250
Liabilities held for sale *(Note 13)*	**3**	–
Deferred credits and other long-term liabilities *(Note 19)*	**169**	147
Future income tax liabilities *(Notes 6 and 24)*	**630**	662
Risk management liabilities *(Notes 7, 8, and 24)*	**123**	78
Non-controlling interests *(Note 5)*	**435**	478
Shareholders' equity		
Common shares *(Notes 20 and 22)*	**2,211**	2,169
Preferred shares *(Notes 21 and 22)*	**293**	–
Retained earnings *(Note 22)*	**533**	634
Accumulated other comprehensive income *(Note 22)*	**140**	126
Total shareholders' equity	**3,177**	2,929
Total liabilities and shareholders' equity	**9,893**	9,786

Contingencies *(Notes 26 and 28)*

Commitments *(Notes 7 and 27)*

Subsequent events *(Note 34)*

See accompanying notes.

On behalf of the Board:

Donna Kaufman

Donna Soble Kaufman
Director

William D. Anderson

William D. Anderson
Director

Consolidated Statements of Comprehensive Income

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009	2008
Net earnings	**219**	181	235
Other comprehensive income			
(Losses) gains on translating net assets of self-sustaining foreign operations	**(60)**	(209)	342
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax[1]	**33**	140	(295)
Gains on derivatives designated as cash flow hedges, net of tax[2]	**164**	280	198
Loss on sale of Mexico equity investment reclassified to the Consolidated Statements of Earnings, net of tax[3] *(Note 24)*	**–**	–	(8)
Reclassification of losses (gains) on derivatives designated as cash flow hedges to the Consolidated Balance Sheets, net of tax[4]	**8**	(11)	8
Reclassification of (gains) losses on derivatives designated as cash flow hedges to net earnings, net of tax[5]	**(129)**	(135)	61
Reclassification of gains on translation of self-sustaining foreign operations to net earnings, net of tax[6]	**(2)**	–	–
Other comprehensive income	**14**	65	306
Comprehensive income	**233**	246	541

1 Net of income tax expense of 6 for the year ended Dec. 31, 2010 (2009 – 26 expense, 2008 – 61 recovery).

2 Net of income tax expense of 87 for the year ended Dec. 31, 2010 (2009 – 120 expense, 2008 – 129 expense).

3 Net of income tax expense of 9 for the year ended Dec. 31, 2008.

4 Net of income tax recovery of 3 for the year ended Dec. 31, 2010 (2009 – 4 expense, 2008 – nil).

5 Net of income tax expense of 65 for the year ended Dec. 31, 2010 (2009 – 69 expense, 2008 – 30 recovery).

6 Net of income tax expense of 3 for the year ended Dec. 31, 2010.

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2010**	2009	2008
Operating activities			
Net earnings	**219**	181	235
Depreciation and amortization *(Note 29)*	**490**	493	451
Gain on sale of equipment	**(4)**	–	(5)
Non-controlling interests *(Note 5)*	**20**	38	61
Asset retirement obligation accretion *(Note 18)*	**21**	24	22
Asset retirement costs settled *(Note 18)*	**(37)**	(35)	(37)
Future income taxes *(Note 6)*	**28**	21	1
Unrealized (gain) loss from risk management activities	**(47)**	2	12
Unrealized foreign exchange gain	**(5)**	(11)	(5)
Asset impairment charges *(Note 3)*	**89**	16	–
Equity loss *(Note 24)*	**–**	–	97
Other non-cash items	**9**	–	(4)
	783	729	828
Change in non-cash operating working capital balances *(Note 30)*	**28**	(149)	210
Cash flow from operating activities	**811**	580	1,038
Investing activities			
Acquisition of Canadian Hydro Developers, Inc., net of cash acquired *(Note 24)*	**–**	(766)	–
Additions to property, plant, and equipment *(Note 12)*	**(790)**	(904)	(1,006)
Proceeds on sale of property, plant, and equipment	**6**	7	30
Proceeds on sale of minority interest in Kent Hills *(Notes 4 and 5)*	**15**	29	–
Restricted cash	**–**	–	248
Resolution of certain tax matters *(Note 11)*	**29**	(41)	(8)
Realized (losses) gains on financial instruments	**(29)**	(16)	52
Loan to equity investment	**–**	–	(245)
Proceeds on sale of equity investment *(Note 24)*	**–**	–	332
Net increase in collateral received from counterparties	**47**	87	–
Net (increase) decrease in collateral paid to counterparties	**(2)**	7	–
Settlement of adjustments on sale of Mexican equity investment	**–**	(7)	–
Other	**4**	6	16
Cash flow used in investing activities	**(720)**	(1,598)	(581)
Financing activities			
Net (decrease) increase in borrowings under credit facilities *(Note 17)*	**(400)**	620	(243)
Repayment of long-term debt *(Note 17)*	**(31)**	(796)	(308)
Issuance of long-term debt *(Note 17)*	**301**	1,119	502
Dividends paid on common shares	**(216)**	(226)	(212)
Funds paid to repurchase common shares under NCIB *(Note 20)*	**–**	–	(130)
Net proceeds on issuance of common shares *(Note 20)*	**1**	398	15
Net proceeds on issuance of preferred shares *(Note 21)*	**291**	–	–
Realized gains on financial instruments	**3**	–	12
Distributions paid to subsidiaries' non-controlling interests *(Note 5)*	**(62)**	(58)	(98)
Other	**–**	(4)	(5)
Cash flow (used in) from financing activities	**(113)**	1,053	(467)
Cash flow (used in) from operating, investing, and financing activities	**(22)**	35	(10)
Effect of translation on foreign currency cash	**(2)**	(3)	9
(Decrease) increase in cash and cash equivalents	**(24)**	32	(1)
Cash and cash equivalents, beginning of year	**82**	50	51
Cash and cash equivalents, end of year	**58**	82	50
Cash taxes (recovered) paid	**(49)**	43	47
Cash interest paid	**153**	149	106

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 three reportable segments.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation segment owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("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.

II. Energy Trading[1]

The Energy Trading segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

Energy Trading 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 and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of all of these activities are included in the Generation segment.

III. Corporate

The Corporate segment 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 to the Generation and Energy Trading groups.

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.

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

1 *The Energy Trading segment was referred to as "Commercial Operations and Development" in 2009 and 2008.*

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 fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are 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. The amounts previously recognized in AOCI are recognized in net earnings when there is a permanent reduction in the hedged net investment as a result of a dilution or sale of the net investment.

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

I. Fuel

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.

II. Energy Trading

Commodity inventories held in the Energy Trading segment are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

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 conditions affecting the Corporation, the market, 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 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, 2010 and 2009.

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 33)*. 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 24 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 future 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. 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. This method has not been applied to the other plans as they did not qualify because the majority of their members are still active. These plans are amortized using Estimated Average Remaining Service Life.

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 AROs 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 accreted 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 31. 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. Compensation expense is reduced by forfeitures in the period they are incurred.

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. Comparative Figures

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

B. Current Year Accounting Changes

I. Inventory

During the second quarter of 2010, the Corporation modified its inventory measurement policy for commodity inventories held in its Energy Trading business segment to better reflect the nature of the underlying inventory and the segment's business objectives. Commodity inventories held in the Energy Trading segment are now measured at fair value less costs to sell, as opposed to the lower of cost and net realizable value. Changes in fair value less costs to sell are recognized in net earnings in the period of change. The effect of this change on current and prior periods was not material. Accordingly, the change has been applied prospectively and prior periods have not been restated.

II. Change in Estimate – Useful Lives

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, TransAlta's economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to the same period in 2009.

Any other adjustments resulting from the review of the balance of the fleet will be reflected in future periods.

C. Prior 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 8.

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.

D. Future Accounting Changes

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

On Jan. 1, 2011, the Corporation adopted IFRS for publicly accountable enterprises as required by the Accounting Standards Board of Canada.

While IFRS uses a conceptual framework similar to Canadian GAAP, there are several significant differences in accounting policies that have been 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 are required, and costs related to major inspection activities are recognized as part of the carrying value of PP&E and depreciated over the period until the next major inspection. For employee future benefits, the Corporation recognizes all experience and transitional gains and losses to retained earnings with subsequent experience gains and losses being recorded in OCI. Long-term contracts deemed to be finance leases resulted in the associated PP&E being removed from the Consolidated Balance Sheets and the recognition of a long-term receivable, representing the present value of lease payments to be received over the life of the contract. A portion of the payments received under the contract are recognized as a reduction of the finance lease receivable and a portion is recognized as interest income, the amount which will vary dependent upon the interest rate and duration of the contract. Provisions for asset retirement obligations are revalued at the end of each quarterly and annual reporting period using current-market based interest rates instead of remaining at historic rates. The related accretion expense is classified as finance (interest) cost under IFRS. Asset impairment testing no longer utilizes undiscounted cash future cash flows to initially assess for impairment. Instead, when an indicator of impairment exists, an asset's carrying amount is compared to the greater of its value in use or fair value less costs to sell. IFRS also requires asset impairment charges to be reversed in subsequent periods if the initial indicator of impairment has reversed.

A steering committee, comprised of senior representatives across the Corporation, continues to monitor the progress of the transition to IFRS and will continue to meet regularly until the first interim report under IFRS is completed in 2011. Quarterly updates are provided to the Audit and Risk Committee.

3. Asset Impairment Charges

During the fourth quarter of 2010, the Corporation completed its annual comprehensive impairment assessment based on fair value estimates derived from the long-range forecast and market values evidenced in the marketplace. As a result, the Corporation recorded a pre-tax impairment charge of $89 million ($79 million after deducting the amount that is attributable to the non-controlling interest) on certain Generation assets, comprised of a $65 million charge against the natural gas fleet and a $24 million charge against the coal fleet. The natural gas fleet impairment reflects lower forecast pricing at one of the Corporation's merchant facilities and the pending sale of the Corporation's 50 per cent interest in the Meridian facility, which had no impact to consolidated earnings as the impairment was attributable to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and primarily reflects the Corporation's shift in 2010 to managing the coal-fired generation facilities on a unit pair basis, resulting in the impairment assessment now being performed on a unit pair basis.

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, the project to develop the Westfield site was placed on hold indefinitely in 2009, and the costs that had been capitalized were expensed.

4. Other Income

During 2010, the 54 megawatt ("MW") expansion of the Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project is approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised their option to purchase a 17 per cent interest in the Kent Hills expansion project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010, and an additional $2 million of proceeds related to costs expected in 2011. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

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

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.

5. Non-Controlling Interests

A. Consolidated Statements of Earnings

Year ended Dec. 31	2010	2009	2008
Stanley Power's interest in TransAlta Cogeneration, L.P. *(Note 33)*	**19**	23	32
25 per cent interest in Saranac Partnership not owned by CE Gen	**–**	14	29
Natural Forces' interest in Kent Hills *(Note 4)*	**1**	1	–
Total	**20**	38	61

B. Consolidated Balance Sheets

As at Dec. 31	2010	2009
Stanley Power's interest in TransAlta Cogeneration, L.P.	**393**	434
25 per cent interest in Saranac Partnership not owned by CE Gen	**15**	16
Natural Forces' interest in Kent Hills	**43**	28
Non-controlling interests portion of OCI	**(16)**	–
Total	**435**	478

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2009	478
Distributions paid	(62)
Non-controlling interests portion of net earnings, including asset impairment *(Note 3)*	20
Non-controlling interests portion of OCI	(16)
Acquisition of minority interest in Kent Hills *(Note 4)*	15
As at Dec. 31, 2010	**435**

C. Consolidated Statements of Cash Flows

Distributions paid by subsidiaries to non-controlling interests are as follows:

Year ended Dec. 31	2010	2009	2008
TransAlta Cogeneration, L.P.	**60**	38	59
Saranac	**–**	18	39
Kent Hills	**2**	2	–
Total	**62**	58	98

6. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2010	2009	2008
Earnings before income taxes	**220**	196	258
Equity loss	**–**	–	(97)
Earnings before income taxes and equity loss	**220**	196	355
Statutory Canadian federal and provincial income tax rate (%)	**28**	29	30
Expected income tax expense	**62**	57	105
(Decrease) increase in income taxes resulting from:			
Lower effective foreign tax rates	**(26)**	(29)	(24)
Resolution of uncertain tax matters	**(30)**	–	(15)
Tax recovery on sale of Mexican equity investment *(Note 24)*	**–**	–	(35)
Effect of tax rate changes	**–**	(6)	–
Statutory and other rate differences	**(10)**	(4)	(7)
Other	**5**	(3)	(1)
Income tax expense	**1**	15	23
Effective tax rate (%)	**1**	8	6

II. Components of Income Tax Expense

The components of income tax expense (recovery) are as follows:

Year ended Dec. 31	2010	2009	2008
Current tax (recovery) expense	**(27)**	(6)	22
Future income tax expense related to the origination and reversal of temporary differences	**28**	27	1
Future income tax recovery resulting from changes in tax rates or laws	**–**	(6)	–
Income tax expense	**1**	15	23

During 2010, TransAlta recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters, which was received in 2010. Interest expense also decreased by $14 million as a result of tax-related interest recoveries.

B. Consolidated Balance Sheets

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

As at Dec. 31	2010	2009
Net operating and capital loss carryforwards	**382**	297
Future site restoration costs	**86**	75
Property, plant, and equipment	**(886)**	(839)
Risk management assets and liabilities, net	**(113)**	(82)
Employee future benefits and compensation plans	**14**	19
Allowance for doubtful accounts	**18**	19
Other deductible temporary differences	**32**	38
Net future income tax liability	**(467)**	(473)

Presented in the Consolidated Balance Sheets as follows:

As at Dec. 31	2010	2009
Assets		
Long-term	**240**	234
Liabilities		
Current	**(77)**	(45)
Long-term	**(630)**	(662)
Net future income tax liability	**(467)**	(473)

7. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost *(Note 1(F))*. The following table highlights the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Dec. 31, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	**–**	**–**	**58**	**–**	**58**
Accounts receivable	**–**	**–**	**428**	**–**	**428**
Collateral paid	**–**	**–**	**27**	**–**	**27**
Risk management assets					
Current	**186**	**79**	**–**	**–**	**265**
Long-term	**204**	**4**	**–**	**–**	**208**
Financial liabilities					
Short-term debt	**–**	**–**	**–**	**1**	**1**
Accounts payable and accrued liabilities	**–**	**–**	**–**	**503**	**503**
Collateral received	**–**	**–**	**–**	**126**	**126**
Dividends payable	**–**	**–**	**–**	**130**	**130**
Risk management liabilities					
Current	**5**	**30**	**–**	**–**	**35**
Long-term	**123**	**–**	**–**	**–**	**123**
Long-term debt recourse[1]	**–**	**–**	**–**	**3,685**	**3,685**
Long-term debt non-recourse[1]	**–**	**–**	**–**	**549**	**549**

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
Long-term receivable	–	–	49	–	49
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	521	521
Collateral received	–	–	–	86	86
Dividends payable	–	–	–	61	61
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

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 inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below:

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 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.

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. Level II fair values are also 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, the Corporation 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 for individual non-standard deals and structured products, 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. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

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.

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments in relation to trading activities and certain contracting activities.

The following table summarizes the key factors impacting the fair value of the energy trading risk management assets and liabilities by classification level during the year ended Dec. 31, 2010:

	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 (liabilities) at Dec. 31, 2009	–	297	(27)	–	–	1	–	297	(26)
Changes attributable to:									
Market price changes on existing contracts	–	146	11	–	(5)	2	–	141	13
Market price changes on new contracts	–	30	–	(1)	10	(2)	(1)	40	(2)
Contracts settled	–	(108)	(4)	–	2	(1)	–	(106)	(5)
Discontinued hedge accounting on certain contracts	–	(46)	–	–	46	–	–	–	–
Net risk management assets (liabilities) at Dec. 31, 2010	**–**	**319**	**(20)**	**(1)**	**53**	**–**	**(1)**	**372**	**(20)**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			7			(1)			6
Realized gain included in earnings before income taxes			4			1			5

To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of the Energy Trading and Generation business segments.

The effect of using reasonable possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at Dec. 31, 2010 is estimated to be +/- $14 million (2009 – $24 million). Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

The total change in Level III financial assets and liabilities held at Dec. 31, 2010 that was recognized in pre-tax earnings for the year ended Dec. 31, 2010 was a $5 million gain (2009 – $1 million).

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

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	182	138	22	(4)	(9)	(10)	319
	Level III	1	1	–	–	–	(22)	(20)
Non-hedges	Level I	(1)	(1)	1	–	–	–	(1)
	Level II	47	1	5	–	–	–	53
	Level III	1	–	–	(1)	–	–	–
Total by level	Level I	(1)	(1)	1	–	–	–	(1)
	Level II	229	139	27	(4)	(9)	(10)	372
	Level III	2	1	–	(1)	–	(22)	(20)
Total net assets (liabilities)		**230**	**139**	**28**	**(5)**	**(9)**	**(32)**	**351**

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt, and the net investment in self-sustaining foreign subsidiaries.

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the year ended Dec. 31, 2010:

	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 liabilities at Dec. 31, 2009	–	(24)	–	–	(2)	–	–	(26)	–
Changes attributable to:									
Market price changes on existing contracts	–	(9)	–	–	2	–	–	(7)	–
Market price changes on new contracts	–	(25)	–	–	–	–	–	(25)	–
Contracts settled	–	21	–	–	1	–	–	22	–
Net risk management (liabilities) assets at Dec. 31, 2010	**–**	**(37)**	**–**	**–**	**1**	**–**	**–**	**(36)**	**–**

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. For hedges that remain effective and qualify for hedge accounting, any change in value will be deferred in AOCI until the instrument is settled, or until such time as the hedged item affects net earnings, or there is a reduction in the net investment in the foreign operations.

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

		2011	2012	2013	2014	2015	2016 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	(1)	(9)	(6)	(2)	(32)	13	(37)
	Level III	–	–	–	–	–	–	–
Non-hedges	Level I	–	–	–	–	–	–	–
	Level II	1	–	–	–	–	–	1
	Level III	–	–	–	–	–	–	–
Total by level	Level I	–	–	–	–	–	–	–
	Level II	–	(9)	(6)	(2)	(32)	13	(36)
	Level III	–	–	–	–	–	–	–
Total net (liabilities) assets		**–**	**(9)**	**(6)**	**(2)**	**(32)**	**13**	**(36)**

	Fair value[1]				Total carrying value
	Level I	Level II	Level III	Total	
Financial assets and liabilities measured at other than fair value					
Long-term debt – Dec. 31, 2010[2]	**–**	**4,460**	**–**	**4,460**	**4,234**
Long-term debt – Dec. 31, 2009[2]	–	4,499	–	4,499	4,442

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, long-term receivable, short-term debt, accounts payable and accrued liabilities, collateral received, and dividends payable).*

2 *Includes current portion.*

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 contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the year is as follows:

As at Dec. 31	**2010**	2009	2008
Unamortized (loss) gain at beginning of year	**(1)**	2	3
New inception gains (losses)	**3**	(1)	1
Amortization recorded in net earnings during the year	**(1)**	(2)	(2)
Unamortized gain (loss) at end of year	**1**	(1)	2

8. Risk Management Activities

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at Dec. 31	2010					2009
	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total	Total
Risk management assets						
Energy trading						
Current	–	**183**	–	**78**	**261**	144
Long-term	–	**185**	–	**4**	**189**	207
Total energy trading risk management assets	–	**368**	–	**82**	**450**	351
Other						
Current	**1**	–	**2**	**1**	**4**	–
Long-term	–	–	**19**	–	**19**	17
Total other risk management assets	**1**	–	**21**	**1**	**23**	17
Risk management liabilities						
Energy trading						
Current	–	–	–	**30**	**30**	30
Long-term	–	**69**	–	–	**69**	50
Total energy trading risk management liabilities	–	**69**	–	**30**	**99**	80
Other						
Current	**5**	–	–	–	**5**	15
Long-term	–	**54**	–	–	**54**	28
Total other risk management liabilities	**5**	**54**	–	–	**59**	43
Net energy trading risk management assets	–	**299**	–	**52**	**351**	271
Net other risk management (liabilities) assets	**(4)**	**(54)**	**21**	**1**	**(36)**	(26)
Net total risk management (liabilities) assets	**(4)**	**245**	**21**	**53**	**315**	245

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (2009 – U.S.$1,100 million), and borrowings under a U.S. dollar denominated credit facility with a face value of U.S.$300 million (2009 – U.S.$300 million) have 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:

Cross-Currency Interest Rate Swap

Outstanding liability resulting from cross-currency interest rate swap used as part of the net investment hedge is as follows:

As at Dec. 31	2010		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
–	–	–	AUD34	(2)	2010

Foreign Currency Contracts

Outstanding foreign currency forward sale (purchase) contracts used as part of the net investment hedge are as follows:

As at Dec. 31	2010		2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
AUD180	**(1)**	**2011**	AUD120	(2)	2010
U.S.(41)	**(3)**	**2011**	U.S.(182)	(1)	2010

ii. Effect on the Consolidated Statements of Comprehensive Income

For the year ended Dec. 31, 2010, a net after-tax loss of $27 million (2009 – loss of $69 million, 2008 – gain of $47 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 tables summarize the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income:

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI for the year ended Dec. 31, 2010	Location of gain reclassified from OCI	Pre-tax gain reclassified from OCI
Long-term debt	**68**	Foreign exchange	**(5)**
Foreign exchange	**(29)**		
OCI impact	**39**	**OCI impact**	**(5)**

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI for the year ended Dec. 31, 2009	Pre-tax loss recognized in OCI for the year ended Dec. 31, 2008
Long-term debt	233	(257)
Cross currency	(3)	(62)
Foreign exchange	(64)	(37)
OCI impact	166	(356)

b. Cash Flow Hedges

i. Energy Trading Risk Management

The Corporation's outstanding energy trading derivative instruments designated as hedging instruments at Dec. 31, 2010, were as follows:

(Thousands)	**Dec. 31, 2010**		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**28,814**	**10**	28,989	–
Natural gas (GJ)	**1,925**	**32,751**	2,163	360
Oil (gallons)	**–**	**12,432**	–	25,074

During the fourth quarter of 2010, unrealized pre-tax gains of $13 million were recognized in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Receipts and Expenditures

The Corporation uses forward foreign exchange contracts to hedge a portion of its future foreign denominated receipts and expenditures as follows:

As at Dec. 31	**2010**			2009			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
217	**U.S.200**	**(12)**	**2011-2017**	91	U.S.78	(8)	2010
U.S.8	**8**	**–**	**2011**	U.S.14	15	–	2010
–	**–**	**–**	**–**	AUD4	U.S.3	–	2010

Foreign Exchange Forward Contracts on Foreign Denominated Debt

Outstanding foreign exchange forward purchase contracts used to manage foreign exchange exposure on debt not designated as a net investment hedge are as follows:

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.300	**(7)**	**2012**	–	–	–
U.S.300	**(7)**	**2013**	–	–	–

Cross-Currency Swap

TransAlta uses cross-currency swaps to manage foreign exchange risk exposures on foreign denominated debt as follows:

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.500	**(28)**	**2015**	U.S.500	(16)	2015

iii. *Interest Rate Risk Management*

The Corporation also had outstanding forward start interest rate swaps that converted floating rate debt into fixed rate debt with fixed rates ranging from 3.5 per cent to 4.6 per cent. These swaps were closed out upon the issuance of the U.S.$300 million senior notes during the first quarter of 2010 and the resulting losses have been included in AOCI and will be amortized to earnings over the original 10-year term of the swaps.

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
–	**–**	**–**	U.S.300	(8)	2020

iv. *Effect on the Consolidated Statements of Comprehensive Income*

Forward sale and purchase commodity contracts, foreign exchange contracts, cross-currency swaps, as well as interest rate 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.

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, 2010

	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 gain recognized in earnings	Pre-tax gain recognized in earnings
Commodity	**299**	Revenue	**(234)**	Revenue	**13**
Foreign exchange loss on project hedges	**(15)**	Property, plant and equipment	**11**	Interest expense	**–**
Foreign exchange loss on U.S. debt	**(14)**	Foreign exchange loss on U.S. debt	**39**		
Cross-currency swaps	**(10)**				
Interest rate	**(9)**	Interest expense	**1**		
OCI impact	**251**	**OCI impact**	**(183)**	**Earnings impact**	**13**

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
Commodity	394	Revenue	(205)	Revenue	–
Foreign exchange loss on project hedges	(31)	Property, plant and equipment	(15)	Interest expense	(2)
Interest rate	37	Interest expense	1		
OCI impact	400	OCI impact	(219)	Earnings impact	(2)

Year ended Dec. 31, 2008

	Effective portion		
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of loss reclassified from OCI	Pre-tax loss reclassified from OCI
Commodity	352	Revenue	91
Foreign exchange gain on project hedges	31	Property, plant and equipment	8
Interest rate	(56)	Interest expense	–
OCI impact	327	OCI impact	99

Over the next 12 months, the Corporation estimates that $121 million 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.

c. Fair Value Hedges

i. 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 6.9 per cent, to floating rate debt through interest rate swaps as shown below *(Note 17)*:

As at Dec. 31	**2010**		2009		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset (liability)	Maturity
100	**2**	**2011**	100	7	2011
U.S.100	**3**	**2013**	U.S.50	(1)	2013
U.S.200	**16**	**2018**	U.S.100	7	2018

Including the interest rate swaps above, 25 per cent of the Corporation's debt is subject to floating interest rates (2009 – 31 per cent).

ii. Effect on the Consolidated Statements of Comprehensive Income

No ineffective portion of fair value hedges was recorded in 2010, 2009, or 2008.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings:

Year ended Dec. 31		**2010**	2009	2008
Derivatives in fair value hedging relationships	Location of gain (loss) on the Consolidated Statements of Earnings			
Interest rate contracts	Net interest expense	**8**	20	(26)
Long-term debt	Net interest expense	**(8)**	(20)	26
Net earnings impact		**–**	–	–

II. Non-Hedges

The Corporation enters into various derivative transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting where 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 these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management

The Corporation enters into certain commodity hedging transactions that are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported as revenue in the period the change occurs. The Corporation's outstanding energy trading derivative instruments that are not designated as hedging instruments were as follows:

(Thousands)	**Dec. 31, 2010**		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**26,553**	**24,924**	14,107	14,844
Natural gas (GJ)	**633,483**	**640,731**	323,793	309,764
Transmission (MWh)	**–**	**7,535**	–	4,852
Oil (gallons)	**–**	**5,040**	–	–

b. 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 resulting from an outstanding cross-currency interest rate swap is as follows:

As at Dec. 31	**2010**			2009	
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
–	**–**	**–**	AUD13	(2)	2010

c. 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 associated with these forward contracts are as follows:

As at Dec. 31	**2010**			2009			
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
20	**AUD20**	**1**	**2011**	–	–	–	–
1	**U.S.1**	**–**	**2011-2012**	–	–	–	–
–	**–**	**–**	**–**	U.S.13	14	–	2010

d. 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 chosen. 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.

e. Effect on the Consolidated Statements of Comprehensive Income

The Corporation 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. During the fourth quarter of 2010, unrealized pre-tax gains of $30 million were recognized in earnings due to certain power hedging relationships being discontinued as they were deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change. For the year ended Dec. 31, 2010, the Corporation recognized a net unrealized gain of $33 million (2009 – $3 million net unrealized loss, 2008 – $14 million net unrealized loss).

The tables below summarize the net realized and unrealized gains and losses included in net earnings that are associated with other risk management derivatives not designated as hedges:

Year ended Dec. 31	**2010**		
	Net unrealized gains	Net realized losses	Total
Foreign exchange	**2**	**(1)**	**1**
Other	**–**	**(1)**	**(1)**

Year ended Dec. 31	2009		
	Net unrealized losses	Net realized losses	Total
Foreign exchange	–	(1)	(1)

Year ended Dec. 31	2008		
	Net unrealized losses	Net realized gains	Total
Foreign exchange	(3)	14	11
Other	–	1	1

B. 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 Energy Trading 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, 2010 associated with the Corporation's proprietary energy trading activities was $5 million (2009 – $3 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.

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, 2010 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $52 million (2009 – $45 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, 2010 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was $6 million (2009 – 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 payments 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, 2010, 2009, and 2008, due to changes in market interest rates affecting the Corporation's floating rate debt 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 a reasonable potential change in market interest rates over the next quarter.

Year ended Dec. 31	**2010**		2009		2008	
	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	**4**	**–**	5	(10)	2	–

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, 2010, 2009, and 2008, due to changes in foreign 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 six cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2010**		2009		2008	
	Net earnings (decrease) increase[1]	OCI gain[1, 2]	Net earnings decrease[1]	OCI gain[1, 2]	Net earnings decrease[1]	OCI gain[1, 2]
U.S.	**(4)**	**9**	(5)	3	(5)	3
AUD	**1**	**-**	(1)	-	(3)	-
Euro	**-**	**-**	-	-	-	3
Total	**(3)**	**9**	(6)	3	(8)	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, 2010, 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, 2010, without taking into account collateral held or right of set-off, 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, net of any collateral held, at Dec 31, 2010 was $43 million (2009 – $63 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, 2010:

(Per cent)	Investment grade	Non-investment grade	Total
Accounts receivable	**96**	**4**	**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 9.

At Dec. 31, 2010, the Corporation did not have any significant past due trade receivables except as disclosed in Note 28.

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 assets and liabilities is as follows:

	2011	2012	2013	2014	2015	2016 and thereafter	Total
Accounts payable and accrued liabilities	503	–	–	–	–	–	503
Collateral received	126	–	–	–	–	–	126
Debt[1]	254	674	629	231	681	1,769	4,238
Energy trading risk management (assets) liabilities[2]	(230)	(139)	(28)	5	9	32	(351)
Other risk management liabilities (assets)[2]	–	9	6	2	32	(13)	36
Interest on long-term debt	237	214	194	157	127	960	1,889
Dividends payable	130	–	–	–	–	–	130
Total	**1,020**	**758**	**801**	**395**	**849**	**2,748**	**6,571**

1 Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.
2 Net risk management assets and liabilities as above.

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2010, $40 million (2009 – $45 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Gen has been pledged as collateral for certain CE Gen debt. Should any defaults occur, the debtholders would have first claim on these assets.

At Dec. 31, 2010, the Corporation provided $27 million (2009 – $27 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.

II. Financial Assets Held as Collateral

At Dec. 31, 2010, the Corporation received $126 million (2009 – $86 million) in cash 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.

III. 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, 2010, the Corporation had posted collateral of $17 million (2009 – $37 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $40 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2010.

9. Accounts Receivable

As at Dec. 31	2010	2009
Gross accounts receivable	**474**	470
Allowance for doubtful accounts *(Note 28)*	**(46)**	(49)
Net accounts receivable	**428**	421

The change in allowance for doubtful accounts is outlined below:

Balance, Dec. 31, 2009	49
Change in foreign exchange rates	(3)
Balance, Dec. 31, 2010	**46**

10. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, are valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which also includes natural gas, is valued at fair value less costs to sell *(Note 2)*. The classifications are as follows:

As at Dec. 31	2010	2009
Coal	**47**	86
Natural gas	**5**	4
Purchased emission credits	**1**	–
Total	**53**	90

The decrease in coal inventory in 2010 compared to 2009 is primarily due to higher production at the coal facilities.

The change in inventory is outlined below:

Balance, Dec. 31, 2009	90
Net consumed	(36)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2010	**53**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2010 and 2009, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

11. Long-Term Receivable

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million.

12. Property, Plant, and Equipment

As at Dec. 31	2010				2009		
	Depreciable lives	Cost	Accumulated depreciation and amortization	Net book value	Cost	Accumulated depreciation and amortization	Net book value
Thermal generation equipment	**2-50**	**4,396**	**2,103**	**2,293**	4,693	2,266	2,427
Mining property & equipment	**3-50**	**917**	**368**	**549**	795	415	380
Gas generation	**2-30**	**2,047**	**955**	**1,092**	2,135	883	1,252
Geothermal generation	**10-20**	**334**	**127**	**207**	333	101	232
Hydro generation	**3-60**	**614**	**255**	**359**	609	238	371
Wind generation	**5-30**	**1,820**	**114**	**1,706**	1,554	59	1,495
Biomass	**10-25**	**2**	**–**	**2**	25	1	24
Capital spares and other	**3-41**	**310**	**87**	**223**	270	65	205
Assets under construction	**–**	**995**	**–**	**995**	1,038	–	1,038
Coal rights[1]	**–**	**148**	**92**	**56**	133	86	47
Land	**–**	**71**	**–**	**71**	68	–	68
Transmission systems	**15-50**	**52**	**28**	**24**	48	28	20
Total		**11,706**	**4,129**	**7,577**	11,701	4,142	7,559

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

The Corporation capitalized $48 million of interest to PP&E in 2010 (2009 – $36 million, 2008 – $21 million).

The change in PP&E is outlined below:

	Cost	Accumulated depreciation and amortization	Net book value
Balance, Dec. 31, 2009	11,701	4,142	7,559
Additions	790	–	790
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	(104)	–	(104)
Assets held for sale *(Note 13)*	(89)	(29)	(60)
Asset impairment charges *(Note 3)*	(80)	–	(80)
Change in foreign exchange rates	(70)	(26)	(44)
Depreciation	–	465	(465)
Disposals	(3)	(1)	(2)
Resolution of certain tax matters *(Note 9)*	(11)	–	(11)
Retirement of assets	(60)	(60)	–
Transfers	13	–	13
Wabamun decommissioning	(381)	(362)	(19)
Balance, Dec. 31, 2010	**11,706**	**4,129**	**7,577**

13. Assets and Liabilities Held for Sale

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, all associated assets and liabilities have been classified as held for sale under the Generation segment. The sale is effective Jan. 1, 2011 and is expected to close in early 2011. The impact of this transaction on net earnings is not expected to be significant.

14. Goodwill

The change in goodwill is outlined below:

Balance, Dec. 31, 2009	434
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	87
Change in foreign exchange rates	(4)
Balance, Dec. 31, 2010	**517**

A portion of goodwill in Generation relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars *(Note 29)*.

15. Intangible Assets

The change in intangible assets is outlined below:

	Cost	Accumulated amortization	Net book value
Balance, Dec. 31, 2009	618	274	344
Adjustment of Canadian Hydro purchase price allocation *(Note 24)*	(10)	–	(10)
Additions	3	–	3
Change in foreign exchange rates	(21)	(13)	(8)
Amortization	–	25	(25)
Balance, Dec. 31, 2010	**590**	**286**	**304**

A portion of intangible assets relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars.

16. Other Assets

As at Dec. 31	**2010**	2009
Deferred license fees	**23**	22
Accrued benefit asset *(Note 32)*	**25**	18
Project development costs	**49**	45
Deferred service costs	**12**	19
Keephills 3 transmission deposit	**8**	8
Other	**10**	9
Total other assets	**127**	121

Deferred license fees consist primarily of licenses 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 licenses relate.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts for projects no longer probable of occurring are charged to expense.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee site. These costs are being amortized over the life of these projects.

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.

17. Long-Term Debt and Net Interest Expense

A. Amounts Outstanding

As at Dec. 31		**2010**			2009	
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**645**	**645**	**1.4%**	1,063	1,063	1.0%
Debentures	**1,057**	**1,076**	**6.7%**	1,055	1,076	6.7%
Senior notes[3]	**1,931**	**1,902**	**6.0%**	1,687	1,684	5.9%
Non-recourse	**549**	**562**	**6.5%**	578	589	6.3%
Other	**52**	**52**	**6.7%**	59	59	6.7%
	4,234	**4,237**		4,442	4,471	
Less: current portion	**(255)**	**(253)**		(31)	(31)	
Total long-term debt	**3,979**	**3,984**		4,411	4,440	

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 *2010 – U.S.$1,900 million, 2009 – U.S.$1,600 million.*

A portion of the fixed rate components of the Corporation's debentures and senior notes have been hedged using fixed to floating interest rate swaps *(Note 8)* and therefore the Corporation has included the fair value of these swaps with the value of the debt which is also recorded at fair value. The balance of long-term debt is not hedged and therefore recorded at amortized 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 revolving credit facility 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. A total of U.S.$300 million of the credit facilities has been designated as a hedge of the Corporation's net investment of U.S. self-sustaining foreign operations. The Corporation also has $240 million available in committed bilateral credit facilities, all of which mature in 2012.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent and have maturity dates ranging from 2011 to 2030.

Senior Notes bear interest at rates ranging from 4.75 per cent to 6.75 per cent and have maturity dates ranging from 2012 to 2040. During 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040. A total of U.S.$800 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 2011 to 2018 and bears interest at rates ranging from 7.5 per cent to 8.3 per cent and includes debt with a cost of U.S.$171 million (2009 – U.S.$192 million). The Wailuku debt has a maturity date of 2021 and bears interest at a floating rate currently of 0.3 per cent and includes debt with a cost of U.S.$7 million (2009 – U.S.$8 million). The Canadian Hydro debt has maturity dates ranging from 2012 to 2018 and bears interest at rates ranging from 5.3 per cent to 10.9 per cent and includes debt with a cost of $363 million and U.S.$20 million (2009 – $365 million and U.S.$20 million).

Other consists of notes payable for the Windsor plant that bear 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 that 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.

TransAlta's debt contains terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2010, the Corporation was in compliance with all debt covenants.

B. Principal Repayments

2011	253
2012	674
2013	629
2014	231
2015	681
2016 and thereafter	1,769
Total [1]	**4,237**

1 *Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.*

C. Interest Expense

Year ended Dec. 31	**2010**	2009	2008
Interest on long-term debt	**243**	183	177
Interest income	**(17)**	(6)	(46)
Capitalized interest	**(48)**	(36)	(21)
Other	**–**	3	–
Net interest expense	**178**	144	110

The Corporation capitalizes interest during the construction phase of growth capital projects. The capitalized interest in 2010 relates primarily to Keephills 3, Ardenville, and Kent Hills. In 2009, the capitalized interest related primarily to Keephills 3 and associated mine capital, Blue Trail, and Summerview 2.

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

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, 2010 totalled $297 million (2009 – $334 million) with no (2009 – nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.0 billion (2009 – $2.1 billion) of committed credit facilities, of which $1.1 billion (2009 – $0.7 billion) is not drawn, and is available as of Dec. 31, 2010, subject to customary borrowing conditions.

In addition to the $1.1 billion available under the credit facilities, TransAlta also has $58 million of cash available.

18. Asset Retirement Obligation

The change in asset retirement obligation balances is summarized below:

Balance, Dec. 31, 2009	282
Liabilities incurred in period	3
Liabilities settled in period	(37)
Accretion expense	21
Transfer to liabilities held for sale *(Note 13)*	(3)
Revisions in estimated cash flows	(20)
Change in foreign exchange rates	(4)
	242
Less: current portion	(38)
Balance, Dec. 31, 2010	**204**

The Corporation has a right to recover a portion of future asset retirement costs.

Revisions in estimated cash flows are primarily due to changes in the estimated costs associated with the decommissioning of the Wabamun plant, which was shut down on March 31, 2010.

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 2011 and 2072. The majority of the costs will be incurred between 2020 and 2050. 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, 2010, the Corporation had provided a surety bond in the amount of U.S.$192 million (2009 – U.S.$192 million) in support of future retirement obligations at the Centralia coal mine. At Dec. 31, 2010, the Corporation had provided letters of credit in the amount of $72 million (2009 – $67 million) in support of future retirement obligations at the Alberta mines.

19. Deferred Credits and Other Long-Term Liabilities

As at Dec. 31	**2010**	2009
Deferred coal revenues *(Note 25)*	**61**	51
Long-term power contracts	**28**	32
Accrued benefit liability *(Note 32)*	**51**	49
Commitments for transportation of natural gas	**9**	–
Long-term incentive accruals	**8**	4
Other	**12**	11
Total deferred credits and other long-term liabilities	**169**	147

The long-term power contracts represent the fair value adjustments for various plants to deliver power at less than the prevailing market price at the time of the acquisition. The long-term power contracts are amortized on a straight-line basis over the life of the contract.

20. Common Shares

A. Issued and Outstanding

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

Year ended Dec. 31	2010		2009	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**218.4**	**2,169**	197.6	1,761
Issued under dividend reinvestment and share purchase plan	**1.6**	**37**	–	–
Issued under stock option plans	**0.1**	**1**	–	–
Issued under Performance Share Ownership Plan	**0.2**	**4**	0.2	6
Issued[1]	**–**	**–**	20.6	402
Issued and outstanding, end of year	**220.3**	**2,211**	218.4	2,169

1 *Net of issuance costs of $12 million after tax.*

On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, 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.$20.75, 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, 2011 and expire after 10 years *(Note 31)*.

At Dec. 31, 2010 the Corporation had 2.2 million outstanding employee stock options (2009 – 1.5 million). For the year ended Dec. 31, 2010, 0.1 million options with a weighted average exercise price of $16.20 were exercised resulting in 0.1 million shares issued, and 0.1 million options were cancelled with a weighted average exercise price of $26.61 *(Note 31)*.

During 2010, no shares were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program prior to its expiry on May 6, 2010. For the year ended Dec. 31, 2009, no shares were acquired or cancelled under the NCIB program. 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.

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 29, 2010.

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, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. During the year ended Dec. 31, 2010, the Corporation issued 1.6 million common shares for $37 million. Under the terms of the DRASP plan, the Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

D. Earnings Per Share

Year ended Dec. 31	**2010**	2009	2008
Net earnings applicable to common shares	**218**	181	235
Basic and diluted weighted average number of common shares outstanding	**219**	201	199
Earnings per common share			
Basic and diluted	**1.00**	0.90	1.18

The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding *(Note 31)*.

E. Dividends

The following tables summarize the common share dividends in 2010 and 2009:

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends	Dividends paid in cash[1]	Dividends paid in shares under DRASP[1]
Jan. 29, 2010	April 1, 2010	0.29	–	63	60	3
April 1, 2010	July 1, 2010	0.29	–	64	49	15
July 22, 2010	Oct. 1, 2010	0.29	–	63	44	19
Oct. 28, 2010	Jan. 1, 2011	0.29	64	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	65		
Total		**1.45**	**129**	**319**		

1 *Allocation of dividends paid in cash or shares will be determined at the payment date.*

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2009	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Jan. 29, 2009	April 1, 2009	0.29	–	57	57	–
April 30, 2009	July 1, 2009	0.29	–	57	57	–
July 23, 2009	Oct. 1, 2009	0.29	–	58	58	–
Oct. 29, 2009	Jan. 1, 2010	0.29	63	63	63	–
Total		**1.16**	**63**	**235**		

21. Preferred Shares

A. Issued and Outstanding

The Corporation is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations.

Year ended Dec. 31	**2010**			
	Number of shares (millions)	Amount	Dividend rate per share	Redemption price per share
Issued and outstanding, beginning of year	**-**	**-**	**-**	**-**
Issued[1]	**12.0**	**293**	**1.15**	**25**
Issued and outstanding, end of year	**12.0**	**293**		

1 *Net of issuance costs of $7 million after tax.*

On Dec. 10, 2010, TransAlta completed a public offering of 12 million Series A Cumulative Rate Reset First Preferred Shares under a prospectus supplement to the short form base shelf prospectus dated Oct. 19, 2009 for gross proceeds of $300 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.15 per share as approved by the Board of Directors, payable quarterly, yielding 4.60 per cent per annum, for the initial period ending March 31, 2016. The dividend rate will reset on March 31, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 2.03 per cent. The preferred shares are redeemable at the option of TransAlta on or after March 31, 2016 and on March 31 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends. The first dividend was declared on Dec. 13, 2010.

The preferred shareholders will have the right to convert their shares into Series B Cumulative Rate Reset First Preferred Shares on March 31, 2016 and on March 31 of every fifth year thereafter. The holders of Series B preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 2.03 per cent.

B. Dividends

The following table summarizes the preferred share dividends declared in 2010:

Date declared	Payment date	Dividend per share ($)	Dividends payable as at Dec. 31, 2010	Total dividends
Dec. 13, 2010	March 31, 2011	**0.3497**	**1**	**1**

22. Shareholders' Equity

A reconciliation of shareholders' equity is as follows:

	Common shares	Preferred shares	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
Balance, Dec. 31, 2009	2,169	–	634	126	2,929
Net earnings	–	–	219	–	219
Shares issued	42	293	–	–	335
Dividends declared on common shares	–	–	(319)	–	(319)
Dividends declared on preferred shares	–	–	(1)	–	(1)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	–	–	–	(27)	(27)
Gains on derivatives designated as cash flow hedges, net of tax	–	–	–	164	164
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	–	–	–	(121)	(121)
Gains on translation of self-sustaining foreign operations transferred to net earnings, net of tax	–	–	–	(2)	(2)
Balance, Dec. 31, 2010	**2,211**	**293**	**533**	**140**	**3,177**

The components of AOCI are presented below:

As at Dec. 31	**2010**	2009
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and of tax	**(92)**	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	**232**	189
Total accumulated other comprehensive income	**140**	126

23. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2010	2009	Increase/ (decrease)
Short-term debt and current portion of long-term debt	**256**	31	225
Less: cash and cash equivalents	**(58)**	(82)	24
	198	(51)	249
Long-term debt			
Recourse	**3,450**	3,857	(407)
Non-recourse	**529**	554	(25)
Non-controlling interests	**435**	478	(43)
Shareholders' equity			
Common shares	**2,211**	2,169	42
Preferred shares	**293**	–	293
Retained earnings	**533**	634	(101)
AOCI	**140**	126	14
	7,591	7,818	(227)
Total capital	**7,789**	7,767	22

Total capital remains largely unchanged from the prior year. The decrease in long-term debt is primarily due to the issuance of preferred shares and favourable foreign exchange movements.

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2009.

TransAlta's objectives in managing its capital structure are as follows:

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 credit 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 seeks to manage the Corporation's capital in line with the following targets:

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 to maintain this ratio 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 to maintain this ratio in a range of 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 to maintain this ratio in a range of 55 to 60 per cent.

These ratios are presented below:

Year ended Dec. 31	2010	2009
Cash flow to interest coverage (times)[1]	**4.3**	4.9
Cash flow to debt (%)[1]	**18.3**	20.5
Debt to invested capital (%)	**53.6**	56.1

1 *Last 12 months.*

The decrease in cash flow to interest coverage resulted from higher interest expense. The decrease in cash flow to debt resulted from an increase in debt balances *(Note 17)*. The decrease in debt to invested capital is due to U.S. dollar denominated debt being valued lower in Canadian dollar terms at Dec. 31, 2010 *(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

For the years ended Dec. 31, 2010 and 2009, net cash outflows, after cash dividends and capital asset additions, are summarized below:

Year ended Dec. 31	2010	2009	Increase in cash flows
Cash flow from operating activities	**811**	580	231
Dividends paid on common shares	**(216)**	(226)	10
Capital asset expenditures	**(790)**	(904)	114
Net cash outflow	**(195)**	(550)	355

The increase in the total net cash flows primarily resulted from higher cash flows from operating activities and lower capital asset expenditures. TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2010, $1.1 billion of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta opportunistically accesses the capital market to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

During 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040.

During 2010, the Corporation issued 1.9 million common shares for total net proceeds of $42 million. The Corporation also issued 12.0 million preferred shares for total net proceeds of $293 million.

TransAlta's formal dividend policy targets to pay common shareholders an annual dividend in the range of 60 to 70 per cent of comparable net earnings, a non-GAAP measure, which in general excludes 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**

Final Allocation of Purchase Price

During the fourth quarter of 2010, the preliminary purchase price allocation was revised to reflect the results of management's assessment of value. The significant adjustments between the preliminary and final purchase price allocation were primarily due to the finalization of the fair values of property, plant, and equipment and intangible assets. As a result, a pre-tax decrease of $4 million has been reflected in depreciation expense. The resulting adjustments and final purchase price allocation are highlighted below:

	Acquisition fair values	Adjustments	Revised balances
Assets:			
Cash	19	–	19
Accounts receivable	25	–	25
Prepaid expenses	5	–	5
Property, plant, and equipment, net	1,291	(104)	1,187
Intangible assets	176	(10)	166
Other assets	22	–	22
Total assets acquired	1,538	(114)	1,424
Liabilities:			
Accounts payable and accrued liabilities	54	2	56
Current risk management liabilities	6	–	6
Long-term debt	931	–	931
Asset retirement obligation	3	–	3
Future income tax liabilities	29	(29)	–
Long-term risk management liabilities	34	–	34
Total liabilities assumed	1,057	(27)	1,030
Net assets purchased	481	(87)	394
Goodwill	304	87	391
Total purchase price	**785**	**–**	**785**

B. Disposals

Mexican Equity Investment

On Oct. 8, 2008, TransAlta successfully completed the sale of the Mexican equity investment to InterGen Global Ventures B.V. 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.

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, 2010, TAGP had received $61 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 *(Note 19)*.

TAGP operates and maintains three combined-cycle power plants in Ontario, a combined-cycle power plant in Fort Saskatchewan, Alberta, and a cogeneration plant in Lloydminster, Alberta on behalf of TA Cogen, which is a subsidiary of TransAlta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited.

For the period November 2002 to October 2012, TA Cogen entered into various transportation swap transactions with TransAlta Energy Marketing Corporation ("TEMC"). 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 two of its plants over the period of the swap. The notional gas volumes in the swap transactions are equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract.

For the period October 2010 to October 2011, TA Cogen entered into physical gas purchase transactions with TEMC for volumes to be consumed by one of its plants.

For the period November 2012 to October 2017, TA Cogen entered into financial and foreign currency swap transactions with TEMC to mitigate the natural gas price exposure at one of its plants.

TEMC has entered into offsetting contracts and therefore has no risk other than counterparty risk.

26. Contingencies

TransAlta is occasionally named as a party in various claims and legal proceedings that 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 unrecorded 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, long-term service 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
2011	8	1	14	55	19	237	106	440
2012	8	6	13	55	18	214	36	350
2013	9	7	12	55	17	194	–	294
2014	8	7	11	55	17	157	–	255
2015	8	7	10	60	9	127	–	221
2016 and thereafter	22	12	52	320	3	960	–	1,369
Total	**63**	**40**	**112**	**600**	**83**	**1,889**	**142**	**2,929**

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 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 extending 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 Sept. 13, 2010, TransAlta obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of its Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012. As at Dec. 31, 2010, the total capital incurred on this project was $3 million.

As part of the acquisition of Canadian Hydro on Oct. 23, 2009, TransAlta assumed the plans to design, build, and operate Bone Creek, a 19 MW hydro facility in British Columbia. The capital cost of the project is estimated at $48 million, net of expected cost recoveries of $6 million, and is expected to begin commercial operations in the first quarter of 2011. As at Dec. 31, 2010, the total capital incurred on this project was $54 million. The total estimated spend for Bone Creek is less than the amount incurred to date due to the timing of project spend and associated recoveries in 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 2012. The capital cost of the projects is estimated at $68 million. As at Dec. 31, 2010, the total capital incurred on these projects was $10 million.

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, 2010, total spend on this project was $928 million.

Growth project commitments are as follows:

	Sundance Unit 3	Keephills Unit 1 uprate	Keephills Unit 2 uprate	Keephills Unit 3	Total
2011	7	14	25	60	106
2012	17	16	3	–	36
2013	–	–	–	–	–
2014	–	–	–	–	–
2015	–	–	–	–	–
2016 and thereafter	–	–	–	–	–
Total	**24**	**30**	**28**	**60**	**142**

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. The remaining electrical capacity from these facilities is sold in 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 two five-year options for extensions to the contracts. The contracts cover up to 202 MWs, or 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. The remaining capacity at Sarnia is available for export to the merchant market, based on market prices. On Sept. 30, 2009, TransAlta entered a new agreement with the Ontario Power Authority to supply up to 444 MWs of electricity to the Ontario electricity market, which expires on Dec. 31, 2025. Electrical production at the remaining Ontario plants is subject to contracts expiring in two to seven 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 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 complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$46 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator and the California Department of Water Resources during the 2000-2001 period. In addition, the California parties have sought additional refunds which to date have been rejected by FERC. TransAlta does not believe the California parties will be successful in obtaining additional refunds and is pursuing cost offsets to the refunds awarded by FERC. TransAlta established a U.S.$46 million provision to cover any potential refunds and continues to seek relief from this obligation. A final ruling is not expected in the near future.

29. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three 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 Energy Trading's intersegment charge for energy marketing in the amount of $5 million (2009 – $32 million, 2008 – $30 million). The intersegment cost allocation (recovery) decreased for the year ended Dec. 31, 2010 as a result of costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010. The change has been applied prospectively and prior periods have not been restated. Energy Trading'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, 2010	Generation	Energy Trading	Corporate	Total
Revenues	**2,778**	**41**	**–**	**2,819**
Fuel and purchased power	**1,202**	**–**	**–**	**1,202**
	1,576	**41**	**–**	**1,617**
Operations, maintenance, and administration	**549**	**17**	**68**	**634**
Depreciation and amortization	**438**	**2**	**19**	**459**
Taxes, other than income taxes	**27**	**–**	**–**	**27**
Intersegment cost allocation	**5**	**(5)**	**–**	**–**
	1,019	**14**	**87**	**1,120**
	557	**27**	**(87)**	**497**
Foreign exchange gain *(Note 8)*				**10**
Asset impairment charges *(Note 3)*				**(89)**
Net interest expense *(Notes 8 and 17)*				**(178)**
Earnings before non-controlling interests and income taxes				**240**

Year ended Dec. 31, 2009	Generation	Energy Trading	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 8)*				8
Asset impairment charges *(Note 3)*				(16)
Net interest expense *(Notes 8 and 17)*				(144)
Other income *(Note 4)*				8
Earnings before non-controlling interests and income taxes				234

Year ended Dec. 31, 2008	Generation	Energy Trading	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 8)*				(12)
Net interest expense *(Notes 8 and 17)*				(110)
Equity loss *(Note 24)*				(97)
Other income *(Note 4)*				5
Earnings before non-controlling interests and income taxes				319

Included above in Generation is $19 million (2009 – $9 million, 2008 – $5 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects and $3 million of government grants received as a reduction of PP&E.

II. Selected Consolidated Balance Sheets Information

As at Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Goodwill *(Note 14)*	**487**	**30**	**–**	**517**
Total segment assets	**9,323**	**132**	**438**	**9,893**

As at Dec. 31, 2009				
Goodwill *(Note 14)*	404	30	–	434
Total segment assets	9,144	148	494	9,786

A portion of goodwill relates to CE Gen, a self-sustaining foreign operation denominated in U.S. dollars.

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Capital expenditures	**759**	**–**	**31**	**790**

Year ended Dec. 31, 2009				
Capital expenditures	879	5	20	904

Year ended Dec. 31, 2008				
Capital expenditures	992	7	7	1,006

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	**2010**	2009	2008
Depreciation and amortization expense on the Consolidated Statements of Earnings	**459**	475	428
Depreciation included in fuel and purchased power	**42**	40	38
Accretion expense included in depreciation and amortization expense	**(21)**	(24)	(22)
Other	**10**	2	7
Depreciation and amortization on the Consolidated Statements of Cash Flows	**490**	493	451

C. Geographic Information

I. Revenues

Year ended Dec. 31	**2010**	2009	2008
Canada	**1,764**	1,631	1,839
U.S.	**951**	1,042	1,165
Australia	**104**	97	106
Total revenue	**2,819**	2,770	3,110

II. Property, Plant, and Equipment and Goodwill

	Property, plant, and equipment *(Note 12)*		Goodwill *(Note 14)*	
As at Dec. 31	**2010**	2009	**2010**	2009
Canada	**6,370**	6,201	**447**	360
U.S.	**1,037**	1,182	**70**	74
Australia	**170**	176	**–**	–
Total	**7,577**	7,559	**517**	434

A change in foreign exchange rates from 2009 to 2010 has resulted in a $44 million decrease in net book value of PP&E and a $4 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. Changes in Non-Cash Operating Working Capital

Year ended Dec. 31	2010	2009	2008
(Use) source:			
Accounts receivable	**(9)**	114	80
Prepaid expenses	**6**	(7)	3
Income taxes receivable	**17**	(1)	(20)
Inventory	**31**	(42)	(10)
Accounts payable and accrued liabilities	**(15)**	(208)	157
Income taxes payable	**(2)**	(5)	–
Change in non-cash operating working capital	**28**	(149)	210

31. Stock-Based Compensation Plans

At Dec. 31, 2010, 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. Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada 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 and is offered to all full-time and part-time employees in the U.S.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia below the level of manager. 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 stock option plans at Dec. 31, 2010 are shown below:

	Options outstanding			Options exercisable	
Range of exercise prices (per share)	Number outstanding at Dec. 31, 2010 (millions)	Weighted average remaining contractual life (years)	Weighted average exercise price (per share)	Number exercisable at Dec. 31, 2010 (millions)	Weighted average exercise price (per share)
11.00-17.01	**0.1**	**2.6**	**14.21**	**0.1**	**14.21**
17.02-23.03	**1.2**	**7.5**	**21.33**	**0.4**	**18.83**
23.04-29.05	**0.1**	**0.3**	**27.70**	**0.1**	**27.70**
29.06-35.05	**0.8**	**7.1**	**32.05**	**0.4**	**32.06**
11.00-35.05	**2.2**	**6.6**	**24.94**	**1.0**	**24.55**

The change in the number of options outstanding under the option plans are outlined below:

Year ended Dec. 31	2010		2009		2008	
	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	**1.5**	**26.36**	1.7	26.80	1.2	19.69
Granted	**0.9**	**22.27**	–	–	1.0	32.10
Exercised	**(0.1)**	**16.20**	–	–	(0.3)	20.52
Cancelled or expired	**(0.1)**	**26.61**	(0.2)	26.47	(0.2)	27.96
Outstanding, end of year	**2.2**	**24.94**	1.5	26.36	1.7	26.80

B. Performance Share Ownership Plan

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. During 2010, the authorized amount was increased to 6.5 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, cannot 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, and the ultimate granting of PSOP in any year is at the discretion of TransAlta's Human Resource Committee. Once a participant's PSOP eligibility for an award has been established, 50 per cent of the shares may be released to the participant when the Board of Directors uses share settlements on the awards, while the remaining 50 per cent will be held in trust for one additional year for employees below vice president level, and for two additional years for employees at the vice president level and above. 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)*	**2010**	2009	2008
Number of awards outstanding, beginning of year	**1.0**	0.9	1.0
Granted	**1.2**	0.5	0.2
Exercised	**(0.2)**	(0.2)	(0.2)
Cancelled or expired	**(0.3)**	(0.2)	(0.1)
Number of awards outstanding, end of year	**1.7**	1.0	0.9

In 2010, pre-tax PSOP compensation expense was $7 million (2009 – $9 million, 2008 – $7 million), which is included in OM&A expense in the Consolidated Statements of Earnings. In 2010, 166,169 common shares were issued at $23.48 per share. In 2009, 224,591 common shares were issued at $24.30 per share. In 2008, 221,855 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, 2010, accounts receivable from employees under the plan totalled $2 million (2009 – $3 million).

D. Stock-Based Compensation

At Dec. 31, 2010, the Corporation had 2.2 million outstanding employee stock options (2009 – 1.5 million).

The Corporation uses the fair value method of accounting for awards granted under its stock option plans. On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, 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.$20.75, 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, 2011 and expire after 10 years. The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model in 2010 and 2008 and the binomial model in 2005 and 2002 using the following assumptions:

	2010	2008	2005	2002
Weighted average fair value per option	**3.67**	6.31	6.84	4.25
Risk-free interest rate (%)	**2.5**	3.6	4.3	5.9
Expected life of the options (years)	**5**	7	10	7
Dividend rate (%)	**5.1**	3.4	5.6	4.9
Volatility in the price of the Corporation's shares (%)	**29.7**	23.2	47.0	28.3

32. 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, 2010. The measurement date used to determine plan assets and accrued benefit obligation was Dec. 31, 2010. The last actuarial valuation for funding purposes of the registered plan was Dec. 31, 2009, and the effective date of the next required valuation for funding purposes is Dec. 31, 2012. 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 $62 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 and retired members (other post-retirement benefits). The latest actuarial valuation of these other plans was as at Dec. 31, 2010. The measurement date used to determine the accrued benefit obligation was also Dec. 31, 2010.

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, 2010	Registered	Supplemental	Other	Total
Current service cost	**2**	**2**	**2**	**6**
Interest cost	**21**	**4**	**2**	**27**
Actual return on plan assets	**(28)**	**–**	**–**	**(28)**
Actuarial loss (gain) on accrued benefit obligation	**30**	**8**	**(3)**	**35**
Difference between expected return and actual return on plan assets	**7**	**–**	**–**	**7**
Difference between amortized and actuarial (gain) loss on accrued benefit obligation for the year	**(26)**	**(8)**	**3**	**(31)**
Amortization of net transition asset	**(9)**	**–**	**–**	**(9)**
Defined benefit (income) expense	**(3)**	**6**	**4**	**7**
Defined contribution expense	**19**	**–**	**–**	**19**
Net expense	**16**	**6**	**4**	**26**

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 on accrued benefit obligation	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 expense	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 on accrued benefit obligation	(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 cost	–	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 expense	17	–	–	17
Net expense	8	5	3	16

In 2010, 2009, and 2008, 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, 2010	Registered	Supplemental	Other	Total
Fair value of plan assets	**304**	**4**	**–**	**308**
Accrued benefit obligation	**382**	**66**	**29**	**477**
Funded status – plan deficit	**(78)**	**(62)**	**(29)**	**(169)**
Amounts not yet recognized in the consolidated financial statements:				
Unrecognized past service costs	**–**	**2**	**2**	**4**
Unamortized transition obligation	**–**	**1**	**–**	**1**
Unamortized net actuarial losses	**103**	**23**	**6**	**132**
Total recognized in the consolidated financial statements:				
Accrued benefit asset (liability)	**25**	**(36)**	**(21)**	**(32)**
Amortization period in years	**15**	**13**	**15**	

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 losses	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	

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, 2010	Registered	Supplemental	Other	Total
Accrued current liabilities	**–**	**4**	**2**	**6**
Other long-term (assets) liabilities	**(25)**	**32**	**19**	**26**
Accrued benefit (asset) liability	**(25)**	**36**	**21**	**32**

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

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				
2011 (expected)	3	4	3	10
Expected benefit payments				
2011	27	3	3	33
2012	27	3	2	32
2013	27	3	2	32
2014	28	4	2	34
2015	28	4	2	34
2016-2020	141	21	13	175

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, 2008	279	3	–	282
Contributions	7	3	2	12
Benefits paid	(26)	(3)	(2)	(31)
Benefits transferred in[1]	4	–	–	4
Effect of translation on U.S. plans	(3)	–	–	(3)
Actual return on plan assets[2]	38	–	–	38
Fair value of plan assets at Dec. 31, 2009	299	3	–	302
Contributions	5	4	3	12
Benefits paid	(26)	(3)	(3)	(32)
Effect of translation on U.S. plans	(2)	–	–	(2)
Actual return on plan assets[2]	28	–	–	28
Fair value of plan assets at Dec. 31, 2010	**304**	**4**	**–**	**308**

1 Transfer of pension assets for addition of employees.
2 Net of expenses.

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 approximately 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, 2010 and 2009 is as follows:

Year ended Dec. 31, 2010 (per cent)	Registered	Supplemental
Equity securities	**51**	**–**
Debt securities	**46**	**–**
Cash and cash equivalents	**3**	**100**
Total	**100**	**100**

Year ended Dec. 31, 2009 (per cent)	Registered	Supplemental
Equity securities	52	–
Debt securities	45	–
Cash and cash equivalents	3	100
Total	100	100

Plan assets do not include any common shares of the Corporation at Dec. 31, 2010. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2010 (2009 – $0.1 million).

The fair value of the total defined benefit plan assets by major asset category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**–**	**147**	**9**	**156**
Debt securities	**–**	**141**	**–**	**141**
Cash and cash equivalents	**7**	**–**	**–**	**7**
Money market investments	**–**	**4**	**–**	**4**
Total	**7**	**292**	**9**	**308**

The fair value of the Canadian defined benefit plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**–**	**138**	**9**	**147**
Debt securities	**–**	**128**	**–**	**128**
Cash and cash equivalents	**3**	**–**	**–**	**3**
Money market investments	**–**	**4**	**–**	**4**
Total	**3**	**270**	**9**	**282**

The fair value of the U.S. defined benefit plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Equity securities	**–**	**9**	**–**	**9**
Debt securities	**–**	**13**	**–**	**13**
Total	**–**	**22**	**–**	**22**

The fair value of the supplemental plan assets by major category at Dec. 31, 2010 is as follows:

Year ended Dec. 31, 2010	Level I	Level II	Level III	Total
Cash and cash equivalents	**4**	**–**	**–**	**4**
Total	**4**	**–**	**–**	**4**

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, 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
Current service cost	2	2	2	6
Interest cost	21	4	2	27
Benefits paid	(26)	(3)	(3)	(32)
Curtailment	(2)	–	(1)	(3)
Effect of translation on U.S. plans	(1)	–	(1)	(2)
Actuarial loss (gain)	30	8	(3)	35
Accrued benefit obligation as at Dec. 31, 2010	**382**	**66**	**29**	**477**

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, 2010 (per cent)	Registered	Supplemental	Other
Accrued benefit obligation at Dec. 31			
Discount rate	**5.2**	**5.3**	**5.0**
Rate of compensation increase	**3.0**	**3.0**	**–**
Benefit cost for year ended Dec. 31			
Discount rate	**6.0**	**6.0**	**5.7**
Rate of compensation increase	**3.0**	**3.0**	**–**
Expected rate of return on plan assets	**7.1**	**–**	**–**
Assumed health care cost trend rate at Dec. 31			
Health care cost escalation	**–**	**–**	**8.5-9.0**[1]
Dental care cost escalation	**–**	**–**	**4.0**
Provincial health care premium escalation	**–**	**–**	**6.0**

Year ended Dec. 31, 2009 (per cent)	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

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, 2010	Registered	Supplemental	Other
1% increase in the discount rate			
Impact on 2010 accrued benefit obligation	**(33)**	**(8)**	**(1)**
Impact on 2011 estimated expense under IFRS	**1**	**–**	**–**
1% decrease in the discount rate			
Impact on 2010 accrued benefit obligation	**39**	**10**	**2**
Impact on 2011 estimated expense under IFRS	**(1)**	**–**	**–**
1% increase in the trend rate			
Impact on 2010 accrued benefit obligation	**–**	**–**	**1**
1% decrease in the trend rate			
Impact on 2010 accrued benefit obligation	**–**	**–**	**(1)**
1% increase in the expected rate of return on plan assets			
Impact on 2011 estimated expense under IFRS	**(3)**	**–**	**–**
1% decrease in the expected rate of return on plan assets			
Impact on 2011 estimated expense under IFRS	**3**	**–**	**–**

U.S. plans:

Year ended Dec. 31, 2010	Pension	Other
1% increase in the discount rate		
Impact on 2010 accrued benefit obligation	**(2)**	**(1)**
Impact on 2011 estimated expense under IFRS	**-**	**-**
1% decrease in the discount rate		
Impact on 2010 accrued benefit obligation	**3**	**1**
Impact on 2011 estimated expense under IFRS	**-**	**-**
1% increase in the trend rate		
Impact on 2010 accrued benefit obligation	**-**	**1**
1% decrease in the trend rate		
Impact on 2010 accrued benefit obligation	**-**	**(1)**
1% increase in the expected rate of return on plan assets		
Impact on 2011 estimated expense under IFRS	**-**	**-**
1% decrease in the expected rate of return on plan assets		
Impact on 2011 estimated expense under IFRS	**-**	**-**

33. Joint Ventures

Joint ventures at Dec. 31, 2010 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 U.S. 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
Project Pioneer	25%	Carbon capture and storage facility 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:

	2010	2009	2008
Results of operations			
Revenues	**449**	539	619
Expenses	**(371)**	(409)	(494)
Non-controlling interests	**(7)**	(34)	(55)
Proportionate share of net earnings	**71**	**96**	**70**
Cash flows			
Cash flow from operations	**133**	111	273
Cash flow used in investing activities	**(211)**	(168)	(376)
Cash flow (used in) from financing activities	**(28)**	(60)	30
Proportionate share of decrease in cash and cash equivalents	**(106)**	**(117)**	**(73)**
Financial position			
Current assets	**139**	147	166
Long-term assets	**2,512**	2,371	2,144
Current liabilities	**(87)**	(114)	(202)
Long-term liabilities	**(374)**	(426)	(503)
Non-controlling interests	**(301)**	(325)	(351)
Proportionate share of net assets	**1,889**	**1,653**	**1,254**

34. Subsequent Events

TransAlta has evaluated subsequent events through to the date the consolidated financial statements were issued. TransAlta has not evaluated any subsequent events after that date.

Sundance Unit 1 and 2 Outage

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of the Sundance facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units were unavailable as inspections were carried out to determine the scope of repairs that may be needed. The units cannot be restarted without inspection and approval from the Alberta Boiler Safety Association. As a result of the outage, production was reduced by 182 gigawatt hours for the year ended Dec. 31, 2010.

Under the terms of the PPA for these units, TransAlta notified the PPA Buyer and the Balancing Pool of a force majeure event. Under force majeure, the Corporation is entitled to receive PPA capacity payments and is protected from having to pay penalties for the units' lack of availability, to the extent the event meets the force majeure criteria set out in the PPA.

On Feb. 8, 2011, the Corporation announced that it had issued a notice of termination for destruction on the Sundance 1 and 2 coal-fired generation units under the terms of the PPA. This action was based on the determination that the physical state of the boilers is such that the units cannot be economically restored to service under the terms of the PPA. Under the PPA, termination for destruction permits the recovery of the net book vale specified in the PPA.

On Feb. 18, 2011, the PPA Buyer provided notice that it intends to dispute the notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. Although no assurance can be given as to the ultimate outcome of these matters, TransAlta believes that they will be resolved in the Corporation's favour. TransAlta remains committed to continuing to work with the PPA Buyer and the Balancing Pool under the processes established within the PPA.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	**2010**	2009	2008
Financial Summary			
Earnings Statement			
Revenues	**2,819**	2,770	3,110
Operating income	**497**	378	533
Net earnings applicable to common shares	**218**	181	235
Balance Sheet			
Total assets	**9,893**	9,786	7,815
Current portion of long-term debt, net of cash and cash equivalents	**198**	(51)	194
Long-term debt	**3,979**	4,411	2,564
Preferred shares of a subsidiary	**–**	–	–
Other non-controlling interests	**435**	478	469
Preferred securities	**–**	–	–
Shareholders' equity	**3,177**	2,929	2,510
Total invested capital	**7,789**	7,767	5,737
Cash Flow			
Cash flow from operating activities	**811**	580	1,038
Cash flow used in investing activities	**(720)**	(1,598)	(581)
Common Share Information (per share)			
Net earnings	**1.00**	0.90	1.18
Comparable earnings[3]	**0.98**	0.90	1.46
Dividends paid on common shares	**1.16**	1.16	1.08
Book value (at year-end)	**13.10**	13.41	12.70
Market price:			
High	**23.98**	25.30	37.50
Low	**19.61**	18.11	21.00
Close (Toronto Stock Exchange at Dec. 31)	**21.15**	23.48	24.30
Ratios (percentage except where noted)			
Debt to invested capital	**53.6**	56.1	48.1
Debt to invested capital excluding non-recourse debt	**50.1**	52.6	45.6
Return on common shareholders' equity	**7.9**	6.9	9.4
Comparable return on common shareholders' equity[3]	**7.7**	6.9	11.6
Return on capital employed	**5.5**	5.7	7.7
Comparable return on capital employed[3]	**6.1**	5.8	9.6
Price/earnings ratio	**21.2**	26.1	20.6
Earnings coverage (times)	**1.8**	1.9	2.8
Dividend payout ratio	**146.3**	129.8	91.5
Dividend payout ratio based on comparable earnings[3]	**149.1**	129.8	74.1
Comparable EBITDA (in millions of Canadian dollars)[3]	**965**	888	1,006
Dividend coverage (times)	**3.8**	2.6	4.8
Dividend yield	**5.5**	4.9	4.4
Cash flow to debt	**18.3**	20.5	31.7
Cash flow to interest coverage (times)	**4.3**	4.9	7.2
Weighted average common shares for the year (in millions)	**211**	201	199
Common shares outstanding at Dec. 31 (in millions)	**220**	218	198
Statistical Summary			
Number of employees	**2,389**	2,343	2,200
Generating Capacity (net MW)[4]			
Coal	**4,688**	4,967	4,942
Gas	**1,869**	1,843	1,913
Renewables	**2,119**	1,965	1,218
Total generating capacity	**8,676**	8,775	8,073
Total generation production (GWh)[5]	**48,614**	45,736	48,891

Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

1 *2002 and 2001 Energy Trading real-time contract revenues are restated to be presented on a gross basis.*
2 *Includes discontinued operations.*
3 *These ratios were calculated using non-GAAP measures. Periods for which the non-GAAP measure was not previously disclosed have not been calculated.*
4 *Represents TransAlta's ownership.*
5 *Includes discontinued operations.*

Ratio Formulas

Debt to invested capital = (debt - cash and cash equivalents) / (debt + non-controlling interests + shareholders' equity - cash and cash equivalents)

Return on common shareholders' equity = net earnings applicable to common shares excluding gain on discontinued operations or earnings on a comparable basis / average common shareholders' equity excluding Accumulated Other Comprehensive Income ("AOCI")

Earnings coverage = (net earnings applicable to common shares + income taxes + net interest expense) / (interest on debt - interest income)

	2007	2006	2005	2004	2003	2002	2001	2000
	2,775	2,677	2,664	2,838	2,509	1,815[1]	2,560[1]	1,587
	541	157	421	478	554	224[2]	469[2]	605[2]
	309	45	199	170	234	190	215	280
	7,157	7,460	7,741	8,133	8,420	7,420	7,878	7,627
	600	296	(66)	(103)	(35)	146	475	221
	1,837	2,221	2,605	3,058	3,162	2,707	2,511	2,201
	–	–	–	–	–	–	–	122
	496	535	559	616	478	263	281	253
	–	175	175	175	451	452	453	292
	2,299	2,428	2,543	2,473	2,460	2,040	1,990	1,957
	5,232	5,655	5,756	6,061	6,516	5,608	5,710	5,046
	847	490	619	613	757	438	716	189
	(410)	(261)	(242)	(65)	(535)	(36)	(1,077)	(205)
	1.53	0.22	1.01	0.88	1.26	1.12	1.27	1.66
	1.31	1.16	0.88	0.70	0.69	0.99	–	–
	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	11.39	11.99	12.80	12.74	12.90	12.01	11.82	11.61
	34.00	26.91	26.66	18.75	19.55	23.95	30.13	22.55
	23.79	20.22	17.67	15.25	15.36	16.69	19.15	13.20
	33.35	26.64	25.41	18.05	18.53	17.11	21.60	22.00
	46.8	44.5	43.9	47.4	47.9	50.9	52.3	48.0
	44.0	41.0	39.9	42.5	42.9	–	–	–
	13.1	1.8	7.0	6.5	10.3	3.5	10.9	11.7
	10.5	9.2	6.8	5.1	5.6	8.2	–	–
	9.8	2.4	7.1	7.5	9.1	4.0	8.7	12.3
	9.7	9.0	7.4	–	–	–	–	–
	21.8	121.1	26.7	21.7	14.7	41.7	17.3	16.7
	3.3	0.5	2.3	1.9	2.0	1.9	3.0	4.0
	65.6	447.7	113.0	120.0	79.0	241.8	78.5	75.8
	76.4	86.0	113.3	150.4	143.7	100.6	–	–
	980	–	–	–	–	–	–	–
	4.2	2.4	3.1	3.2	4.1	2.6	4.3	1.1
	3.0	3.8	3.9	5.5	5.4	5.8	4.6	4.6
	30.7	26.2	23.0	18.5	17.9	16.1	21.8	25.3
	6.6	5.5	4.7	4.1	3.3	3.8	5.5	5.5
	202	201	197	193	185	170	169	169
	201	202	199	194	191	170	168	169
	2,201	2,687	2,657	2,505	2,563	2,573	2,656	2,363
	4,942	4,887	4,885	4,778	4,777	4,966	5,090	5,016
	1,960	1,953	1,933	2,444	2,499	1,333	1,108	1,054
	1,122	1,122	1,117	1,115	1,046	845	800	800
	8,024	7,962	7,935	8,337	8,322	7,144	6,998	6,870
	50,395	48,213	51,810	54,560	53,134	46,877	44,136	40,644

Return on capital employed = (earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense) / average annual invested capital excluding AOCI

Dividend yield = dividend per common share / current year's close price

Dividend payout ratio = common share dividends / net earnings applicable to common shares excluding gain on discontinued operations or earnings on a comparable basis

Price/earnings ratio = current year's close price / basic earnings per share from continuing operations

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + net interest expense) / (interest on debt - interest income)

Dividend coverage = cash flow from operating activities / cash dividends paid on common shares

Cash flow to debt = cash flow from operating activities before changes in working capital / (two-year average of total debt – average cash and cash equivalents)

Comparable EBITDA = operating income + accretion per the Consolidated Statements of Cash Flows + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

Shareholder Information

Annual Meeting

The Annual meeting will be held at 11:00 a.m. MST on Thursday, April 28, 2011, at the Metropolitan Conference Centre, 333 Fourth Avenue S.W., Calgary, Alberta.

Transfer Agent

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Station
Toronto, Ontario M5C 2W9

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1.800.387.0825 toll-free
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416.643.5500

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Fax
416.643.5501

Website
www.cibcmellon.com

Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares:
TSX: TA, NYSE: TAC
TransAlta Corporation preferred securities:
TSX: TA.Pr.D

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:
Investor Relations
TransAlta Corporation
P.O. Box 1900, Station "M"
110 - 12th Avenue S.W.
Calgary, Alberta T2P 2M1

Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

Special Services for Registered Shareholders

Service	Description
Dividend reinvestment and share purchase plan[1]	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.
1 Also available to non-registered shareholders.

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split[2]
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares[3] 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.
2 The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988, share split.
3 TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. In determining the level of the dividend, the Board assesses the dividend payout as a percentage of earnings and as a percentage of cash flow from operations over a period of time. The Board continues to focus on building sustainable earnings, cash flow, and dividend growth and has adopted a formal dividend policy that targets to pay shareholders an annual dividend in the range of 60 to 70 per cent of comparable earnings.

Common Share Dividends Declared

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2010	March 1, 2010	Feb. 25, 2010	$0.29
July 1, 2010	June 1, 2010	May 28, 2010	$0.29
Oct. 1, 2010	Sept. 1, 2010	Aug. 30, 2010	$0.29
Jan. 1, 2011	Dec. 1, 2010	Nov. 29, 2010	$0.29
April 1, 2011	March 1, 2011	Feb. 25, 2011	$0.29

Dividends are paid on the first of the month in January, April, July, and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Dividend Declaration for Preferred Shares

Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue December 10, 2010 to but excluding March 31, 2016.

Preferred Share Dividend Declared

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2011	March 1, 2011	Feb. 25, 2011	$0.3497[4]

Dividends are paid on the last day of the month in March, June, September, and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.
4 The first quarterly dividend payable is based on a longer period, starting from the issue date of December 10, 2010 to March 31, 2011.

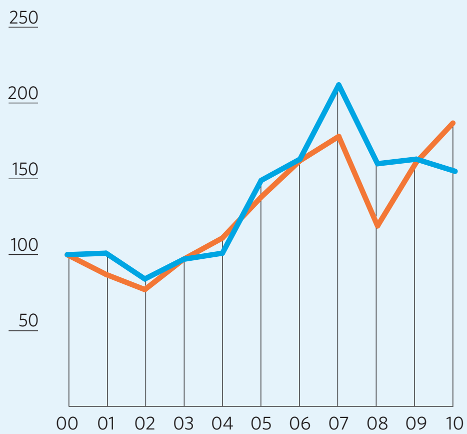
Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Vice-President & Corporate Secretary of the Corporation.

Shareholder Highlights

Total Shareholder Return vs. S&P/TSX Composite Total Return Index

Year Ended Dec. 31 *($)*



TransAlta

100 101 84 97 101 149 163 212 160 163 155

S&P/ TSX Composite

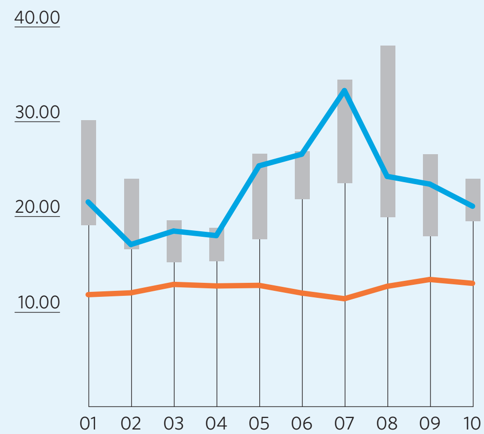
100 87 77 97 111 138 162 178 119 161 189

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2000 would be worth today, assuming the reinvestment of all dividends.

Source: Thompson Financial

Ten-Year Trading Range and Market Value vs. Book Value

($ per share)



Market Value

21.60 17.11 18.53 18.05 25.41 26.64 33.35 24.30 23.48 21.15

Book Value

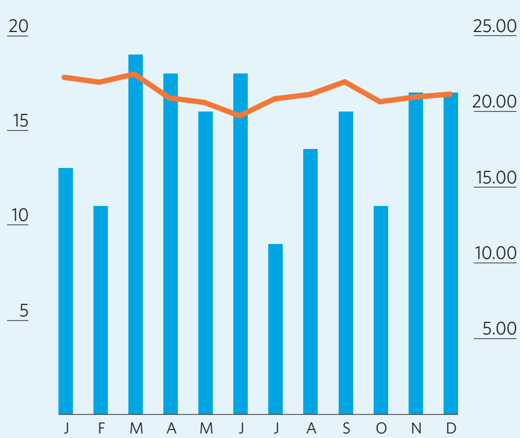
11.82 12.01 12.90 12.74 12.80 11.99 11.39 12.70 13.41 13.10

Trading Range

Source: Thompson Financial and TransAlta (MD&A)

Monthly Volume and Market Price

(2010)



Volume (millions of shares)

13 11 19 18 16 18 9 14 16 11 17 17

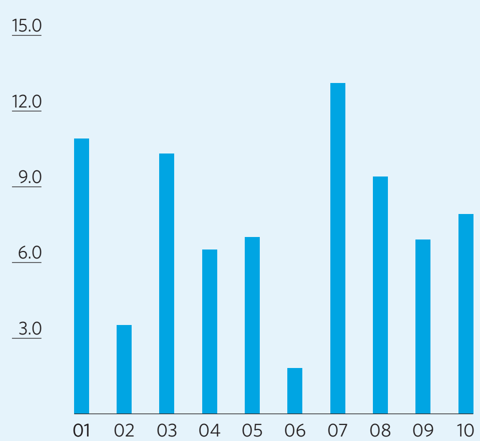
TSX closing market price on last day of the month ($ per share)

22.26 21.94 22.47 20.90 20.60 19.72 20.84 21.13 21.96 20.65 20.96 21.15

Source: Thompson Financial

Return on Common Shareholders' Equity

(%)



10.9 3.5 10.3 6.5 7.0 1.8 13.1 9.4 6.9 7.9

Source: TransAlta (MD&A)

Corporate Information

TransAlta Corporate Officers

Stephen G. Snyder
President & Chief Executive Officer

Dawn Farrell
Chief Operating Officer

Brett Gellner
Chief Financial Officer

Ken Stickland
Chief Legal Officer

William D.A. Bridge
Chief Technology Officer

Michael Williams
Chief Administration Officer

Hume Kyle
Vice-President, Controller & Treasurer

Maryse St.-Laurent
Vice-President & Corporate Secretary

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
www.fsc.org Cert no. SW-COC-002068
© 1996 Forest Stewardship Council
FSC

TransAlta Subsidiaries

Lou Florence
President, TransAlta Centralia Generation & Mining LLC

Aron Willis
Country Manager, TransAlta Energy (Australia) Pty Ltd.

Corporate Governance—New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair, Committee Chair, President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Ethics Help-Line

The Audit and Risk Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors, shareholders, and other stakeholders to call with respect to accounting irregularities, ethical violations, or any other matters they wish to bring to the attention of the Board.

The Ethics Help-Line number is **1.888.806.6646**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

This report was printed in Canada by Blanchette Press on FSC Certified paper. The paper, paper mills, and printer are all Forest Stewardship Council certified, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests. The report was produced in a printing facility that results in nearly zero volatile organic compound (VOC) emissions.

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Glossary

Air Emissions: Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury, and greenhouse gases.

Alberta Power Purchase Arrangement (PPA): A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Availability: A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler: A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Brownfield Asset: A previously constructed electric power generating facility.

Btu (British Thermal Unit): A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

Capacity: The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Carbon Capture and Storage (CCS): An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

CO_2 Emissions Intensity: Amount of carbon dioxide emitted per MWh produced.

Coal Gasification: The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen, or a variety of other chemical products.

Cogeneration: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate: To lower the rated electrical capability of a power generating facility or unit.

Expected Capability: Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

Flue Gas Desulphurization Unit (Scrubber): Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure: Literally means “greater force”. These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigajoule (GJ): A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW): A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh): A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenfield Asset: A new electric power generating facility built from the ground up on a new site.

Greenhouse Gas (GHG): Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Heat Rate: A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW): A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh): A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant Assets: TransAlta uses the term merchant to describe assets that have contracts with terms less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short and medium-term contracts.

Net Maximum Capacity: The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Peaker Plant: A plant usually housing low-efficiency steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment normally used during peak load periods.

Renewable Power: Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Reserve Margin: An indication of a market’s capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Run Rate: The result of extrapolating financial data collected from a period of time less than one year to a full year.

Spark Spread: A measure of gross margin per MW (sales price less cost of natural gas).

Supercritical Technology: The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Target Zero: TransAlta’s initiative designed to drive health, safety and environmental performance to zero lost-time, medical aid, and environmental incidents.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround: Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage: The shutdown of a generating unit due to an unanticipated breakdown.

Uprate: To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR): A measure to manage earnings exposure from energy trading activities.

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TransAlta™

2011 Annual Report

DELIVERING SUSTAINABLE GROWTH

TransAlta™

TRANSALTA IS DELIVERING SUSTAINABLE GROWTH AND SHAREHOLDER VALUE THROUGH DIVERSIFICATION, STRONG AVAILABILITY, BUILDING MORE MEGAWATTS AND FINANCIAL STRENGTH.

Cover: Dan Dowhan is an operations permit coordinator at our Keephills 3 plant. For more information about Keephills 3, please visit transalta.com/keephills3

financial highlights

TransAlta improved its financial performance in 2011 with a seven per cent increase in comparable earnings per share over 2010.

Year ended Dec. 31 *(in millions of Canadian dollars except per common share data and ratios)*	**2011**	2010
Revenues	**2,663**	2,673
Net earnings attributable to common shareholders	**290**	255
Comparable earnings[1]	**230**	213
Comparable EBITDA[1]	**1,077**	955
Funds from operations[1]	**809**	805
Cash flow from operations	**694**	838
Free cash flow[1]	**181**	172
Per common share data		
Net earnings attributable to common shareholders	**1.31**	1.16
Comparable earnings[1]	**1.04**	0.97
Funds from operations[1]	**3.64**	3.68
Dividends paid	**1.16**	1.16
Ratios		
Cash flow to interest *(times)*	**4.4**	4.6
Cash flow to total debt *(%)*	**20.2**	19.6
Debt to invested capital *(%)*	**52.4**	53.1

1 *Comparable earnings, comparable Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA), funds from operations, comparable earnings per share, funds from operations per share and free cash flow are not defined under International Financial Reporting Standards (IFRS). Refer to the non-IFRS financial measures section of the Management's Discussion and Analysis for an explanation and, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operations.*

corporate highlights

- ***Introduced a new senior leadership team, including Dawn Farrell as President and CEO and Ambassador Gordon Giffin as Chair of the Board of Directors.***
- ***Commissioned our new Keephills 3 facility, one of Canada's largest and most advanced cleaner-coal facilities, and our 19 megawatt (MW) Bone Creek hydro facility. Advanced our New Richmond wind facility, scheduled for commercial operation in late 2012.***
- ***Progressed with planning our new 700 MW gas-fired Sundance 7 generating facility, and announced our intent to build Sundance 8 & 9.***
- ***Washington Governor Christine Gregoire signed the TransAlta Energy Transition Bill into law on April 29, 2011. The signing of the bill represents significant collaboration around the common goal of reducing emissions from energy production without unduly disrupting the local economy.***
- ***Contributed to the global body of knowledge on Carbon Capture and Storage (CCS) through the front-end engineering and design phase of Project Pioneer.***

delivering sustainable growth

TransAlta enters 2012 as one of Canada's largest publicly traded providers of renewable power, with a strong presence in Alberta – the continent's fastest growing deregulated electricity market – and across Canada. TransAlta also has a strong presence in the Western U.S. and Western Australia, and has set aggressive goals for growth in each of its key markets.

With experienced leadership, talented employees and a clearly defined strategy rooted in our competitive strengths, we're well positioned to pursue our portfolio of power generating opportunities and to deliver stable returns to shareholders.

Here's how:

Operationally focused

- 89 – 90 per cent availability
- Stable OM&A
- Strong safety performance

We invest significant capital to manage the performance reliability and operational flexibility of our generating assets. We're targeting 89 - 90 per cent availability across our fleet, which can only come from good plant performance. Our efforts to update control systems, expand our operational diagnostic capabilities and improve plant system reporting capabilities have made a difference. Our emphasis on planning and consistent execution is helping us reach this goal and we will do so while keeping our Operations Maintenance and Administration (OM&A) costs down. We are focused on industry leading safety practices with a target Injury Frequency Rate (IFR) below 1.0.

We're competing to win

- #1 in Alberta
- Top 5 in Western U.S.
- Top renewable provider in Canada

We set our growth targets high and we are focused in our efforts to achieve them. In 2011, we partnered in introducing one of Canada's most advanced coal-fired generating facilities, Keephills 3, adding 450 MW of new capacity to the Alberta market. We also brought the 19 MW Bone Creek hydro facility online, and began construction on the 68 MW New Richmond wind facility in Quebec. We also significantly advanced the planning process for the 700 MW Sundance 7 facility, and announced our Sundance 8 and 9 development initiatives.

Our overarching goal is to be Alberta's #1 power generator and energy marketer. It's our home base and our top priority. We plan to replicate this success and become one of the top five power generators in the Pacific Northwest where we operate the coal-fired Centralia facility. Just last year we opened our new U.S. headquarters in Olympia, Washington, demonstrating our commitment to achieving this goal.

Finally, we continue to target renewables across Canada and will also look for other investments in Western Australia. Both of these countries offer compelling opportunities for steady growth.

We're diversified

- 5 fuels – coal, wind, hydro, gas and geothermal
- 3 key markets – Canada, Western U.S., Western Australia

Our five-fuel strategy is a fundamental strength. TransAlta's power portfolio integrates the benefits of five generating source fuels: coal, wind, hydro, gas and geothermal. Being diversified improves our resilience, reduces volatility and enables us to select choice opportunities. Our diversified geographic base extends this advantage even further.

We've got the financial strength

- Strong cash flow
- Investment grade balance sheet

A successful company must have the financial strength and flexibility to build value through all market cycles. TransAlta's financial strength enables us to do just that. With strong cash flows and access to both the Canadian and U.S. capital markets, we are well-positioned to take advantage of opportunities as they arise. Our diversification in fuel sources, geographies, contract terms, and assets supports our investment grade balance sheet and ultimately our low-to-moderate risk profile.

Keephills 3, located west of Edmonton, Alberta

letter to shareholders

Dawn Farrell, President and Chief Executive Officer

As I assume the position of CEO of TransAlta, I am honoured to have been asked to lead a company with such a strong and remarkable history. I look forward in this letter to discussing our 2011 results, and our plans for the next few years.

TransAlta's improved financial performance in 2011 is a testament to our team's ability to adapt to rapidly changing circumstances, and the benefits of a diversified portfolio of assets, fuel types and geographies. We faced significant challenges over the year, but delivered solid results and positioned ourselves to deliver on our strategic priorities in 2012 and beyond.

Our generation business started the year with goals of achieving 89 – 90 per cent availability in the safest way possible. We faced challenges along the way like the shutdown of Sundance Units 1 and 2 and the unplanned outage at Genesee 3, but managed to achieve 88.2 per cent availability with our best safety record ever. Our IFR for 2011 reached 0.89, well ahead of our target of 1.0, which we didn't expect to hit until 2015.

Our Energy Trading business had an outstanding year – one of our best on record. This team came into 2011 with the goal of delivering $50 – $70 million in gross margin, a difficult goal considering the weak market conditions we were seeing at the end of 2010. Not only did they achieve this goal, they far exceeded it.

While we had braced for weak markets, by April it was clear Alberta would surpass expectations as the economy further recovered and electricity demand increased by 2.6 per cent. It was also clear the strength in the Alberta market would be offset by weaker than expected economic conditions in the Pacific Northwest along with the strongest water year in almost 15 years, which drove down revenues from our Centralia operations.

In 2011, we increased comparable earnings per share by seven per cent, delivered Funds From Operations (FFO) of $809 million, and increased free cash flow by 5 per cent.

The strengthening Alberta economy has been a welcome development for TransAlta. We've been waiting for the rebound for some time and we were ready for it when it came. Over the past five years, TransAlta has added 636 MW of supply in Alberta, including our share of the Keephills 3 facility which opened in the fall of 2011. With 4,698 MW of net generating capacity in Alberta out of our total fleet of 8,386 MW, our shareholders are well-positioned to participate in Alberta's growth.

The Pacific Northwest was more challenging. We responded to historically weak market conditions by extending our planned outage at Centralia and reducing costs. We also deferred our efforts to secure long-term contracts for Centralia from 2011 into 2012 and 2013. A key goal over the next two years is to find a market – at the right price – for this long-term, stable power.

2011 was also our first full year producing more than 1,000 MW of wind. TransAlta is now Canada's largest generator of wind power, comprising nearly one third of the country's capacity. By year end, our fleet met our expectations of 2,700 GWhs across 15 wind farms in four provinces. While wind conditions were average, our 95.7 per cent availability led to strong profitability from our fleet. We are also realizing significant productivity gains from our new Wind Control Centre in Pincher Creek, which allows us to optimize production at our wind sites across the country.

2011 was a good year for the hydro fleet, as it maintained a reliability factor of 97.7 per cent. Hydro saw a strong water year, producing over 2,000 GWhs of energy, a 12 per cent increase in overall energy production over the previous year.

We have started our life extension investments in our hydro fleet with outages at Spray and Pocaterra, and over the next 10 years we will continue to make those investments to extend their lives for another 40 to 50 years. This provides significant future value for shareholders.

TransAlta's gas fleet also had a steady year, with strong availability and good contracts. We are building on this success to capitalize on our knowledge of the Alberta market and help meet growing demand for energy to keep pace with the province's long-term economic growth. To this end, we advanced planning for the development of the 700 MW Sundance 7 gas plant, and announced plans for Sundance 8 and 9. In total, these three gas plants will add between 2,000 and 2,400 MWs. In addition to providing strong cash flow to support TransAlta's growth and dividends well into the future, they will be a major source of reliable and affordable power for Albertans.

In our coal fleet, our 2011 plans clearly did not anticipate the failures of the Sundance 1 and 2 Units. Sun 1 and 2 were commissioned in 1970 and 1973, and would have turned 45 in 2015 and 2018, respectively. Both were taken down in late 2010 after a routine inspection and subsequent testing determined corrosion fatigue conditions in the boilers were beyond an acceptable safety factor. After extensive analysis by our engineering teams, manufacturer's representatives and independent third-party experts, we determined the cost to replace the boilers would far exceed the expected future income. Accordingly, we filed a claim for economic destruction under the Power Purchase Agreements (PPAs) and are currently preparing for arbitration proceedings. The results will be known sometime in mid-2012. We are confident in our case and look forward to eliminating the uncertainty this process has caused.

Other challenges in our coal fleet included unexpected outages at Sundance 6 and Genesee 3. We optimized our operations where we could to partially offset some of the impacts associated with these outages and still deliver strong results.

In terms of our Energy Trading business, a strengthened team and strong market conditions in some of our trading regions allowed us to generate gross margins of $137 million, which surpassed our expectations and were significantly higher than 2010. While we believe that over the next five years we can grow this business to a sustainable gross margin level in the $80 – $100 million dollar range, we continue to plan as if the business will deliver closer to its historical results of $50 – $70 million. One year does not make a trend, but it does help us see the potential for the business over the longer term.

TransAlta's Energy Trading business operates within the highest ethical standards. To this end, in 2011 we worked closely with the Alberta Market Surveillance Administrator (MSA) to resolve actions taken in 2010 by the company due to a misinterpretation of market rules. We apologize to our shareholders and customers for the confusion created by the issue. We continue to be a company of the highest integrity and are taking the resulting process around the settlement seriously. In response to this situation, we continue to strengthen our compliance program as a part of our broader drive for operational excellence.

Our Customer business also grew substantially with the acquisition of Nexen's customer business. We now provide more than 400 MW of power to more than 1,500 customers across Alberta, including Heritage Frozen Foods Ltd. and Home Depot Canada Inc. We've been able to maintain or renew over 85 per cent of the Nexen contract volumes, ahead of our 50 per cent target. We are on track to achieve our goal of capturing 30 per cent market share by 2020.

In late 2010, we raised $300 million in preferred shares and another $275 million in November of 2011. We also renewed our $1.5 billion four-year syndicated credit facility through to mid-2015 and extended the maturity on our $240 million bilateral loans to late 2013.

We have done all of this with a team and Board of Directors that is committed to maintaining investment grade credit ratings and ensuring we optimize our financing costs and maintain a low cost of capital to finance our long-term growth strategy.

Looking ahead to 2012, we continue to drive our three key priorities:

Drive the Base

This priority continues to be critical to the success of TransAlta's operational strategy. At the core of driving the base are high availability, profitability, cost competitiveness and production. A key deliverable relating to production is our re-investment in the coal fleet. This program will end in 2012, as we prepare to run the plants to the end of the PPAs and beyond. In 2012 we will perform extended outages at Keephills 1 and 2 to set those plants up for their end of lives in 2028 and 2029, respectively.

Operationally, we are targeting 89 to 90 per cent availability across the fleet, stable generation OM&A to offset inflation, managing major maintenance costs for our coal fleet and a superior safety performance record with an IFR of less than 1.0.

On a long-term basis, our coal fleet asset plans have been developed with the current proposed federal regulation for greenhouse gases as a backdrop. This means CCS will be required for coal plants to run beyond 45 years. We continue to speak with governments regarding the coal regulations and are seeking modifications to the federal government's proposed regulations that will provide additional flexibility.

Sustainable Growth

In November, we announced our intention to grow. We set several goals for ourselves based on our analysis of our competitive strengths in the markets we serve. Specifically, they are to be the #1 generator in Alberta, one of the Top 5 generators in the Pacific Northwest, to maintain our position as one of Canada's largest publicly traded companies in renewable power, and to be the supplier of choice in Western Australia.

To be clear, we will not seek growth for growth's sake. Our growth initiatives must be accretive to the current asset base over the long term and we are confident that the capital markets will support the kinds of investments we intend to bring forward.

Energizing People

We have an outstanding team in place across the company, at the senior management level and throughout our organization. Our success through a very turbulent 2011 is a direct reflection of the quality of our people and their ability to work together. They carry these values and successes into 2012.

In 2011, we appointed a new senior team to take the company forward following the retirement of Steve Snyder. It is a strong team with more than 200 years of experience in our sector. They bring a diverse set of strengths and talents and they have the personal values to work collectively as a team for the benefit of the company. More importantly, they are dedicated to bringing their energy, talent and experience to both the short-term and the long-term success of TransAlta.

TransAlta Corporate Officers 2012 *(left to right)*
Hugo Shaw, Executive Vice-President, Operations; Brett Gellner, Chief Financial Officer; Dawn de Lima, Chief Human Resources Officer and Executive Vice-President, Communications; Robert Emmott, Chief Engineer; Rob Schaefer, Executive Vice-President, Corporate Development; Ken Stickland, Chief Legal and Business Development Officer; Dawn Farrell, President and Chief Executive Officer; Paul Taylor, President, U.S. Operations; Cynthia Johnston, Executive Vice-President, Corporate Services

Our goal as a team is to deliver total shareholder returns in the range of 8 to 10 per cent each year on average, through a combination of dividend yield and growth, while maintaining investment grade credit ratings. We are spending time ensuring all the employees on the TransAlta team understand what it means to create shareholder value and are strong participants in the decisions we need to make to deliver on our promise.

We see both challenge and opportunity on the horizon. Our focus on operational excellence and sustainable growth have positioned us to be able to innovate and compete, to adapt to challenges in our coal-fired fleet and changes to our energy mix, and to leverage new growth opportunities here in Alberta, the Western U.S. and Western Australia.

In closing, my personal thanks to Steve Snyder and our Board of Directors for their confidence in the ability of our team to take TransAlta forward into some very exciting times. More importantly, many thanks to the 2,180 dedicated TransAlta employees and their families who spend enormous time and energy ensuring your company is well-run and well-positioned to serve its customers.

Sincerely,

Dawn Farrell
President and Chief Executive Officer

March 2, 2012

message from the chair

Ambassador Gordon D. Giffin, Chair of the Board

I have had the honour of serving as Chair of your Board of Directors for the past year. To say the last twelve months have been eventful for TransAlta would be an understatement.

Our company has faced significant economic head winds for the past few years. Nevertheless, our team at TransAlta has retained its focus on providing reliable, economical electricity to our customers while maintaining and growing value for our shareholders. TransAlta is proud to be Canada's largest publicly traded wholesale power producer, and the country's largest producer of renewable power.

One of the most important responsibilities of a Board of Directors is to ensure seamless and effective transitions in company governance and management, at the appropriate time. In the past twelve months your board has done just that in transitioning the roles of Board Chair and Chief Executive Officer.

As of January 1, 2012, Steve Snyder retired as our CEO. Steve is a remarkably gifted professional and a wonderful individual. He led TransAlta for sixteen years through regulatory changes and economic challenges, building the business foundation for the growth and development we anticipate in the future. The entire TransAlta team will miss Steve's energy and dedication, and wishes him all the best.

The Board was delighted that Mrs. Dawn Farrell, who has served as our Chief Operating Officer for the past two years, was willing to succeed Steve as President and CEO. Dawn has been in the power industry for more than 25 years, 23 of them with TransAlta. Our Board was proud to name her as President and CEO and to appoint her to the Board on January 2 of this year. We have enormous confidence in Dawn's capacity, judgment, focus and experience and know that she and her senior executive team will lead the growth and development of TransAlta in exemplary fashion during a very dynamic period for the industry.

I was honoured to succeed Mrs. Donna Soble Kaufman as Board Chair at our last Annual General Meeting. Donna was the model for a successful director and chair and made significant contributions to TransAlta during her tenure. Again, the Board pursued a well-defined and diligent process to ensure that a seamless transition occurred in this role.

On behalf of your Board, I can assure you that TransAlta remains dedicated to the responsible growth and development of this company in the service of our customers and in the interest of our shareholders.

We place a strong emphasis on responsible and sustainable development of generating capacity, with continued commitment to diverse fuel sources. Our pursuit of carbon capture technology and the development of the Keephills 3 plant, a 450 MW coal-fired facility that uses state-of-the-art technology to reduce CO_2 emissions are two significant examples. While the company is successfully transitioning to other fuel sources, the continued focus on public policies and technologies which can maintain the responsible availability of coal-fired generation is in both the public and company's interests.

The TransAlta Board of Directors is a talented and dedicated group of stewards of your company. In 2012, we will maintain our focus on the safe, responsible, reliable, profitable generation of electric power in the markets we serve. We are committed to prudent capital allocation, responsible cost management and a strong dividend. Our company is strong, our management is focused and talented, and our goals are clear.

Sincerely,

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chair of the Board

March 2, 2012

TransAlta Board of Directors 2011 *(left to right)*
Gordon Lackenbauer, Martha Piper, Stephen Baum, Timothy Faithfull, Michael Kanovsky, Karen Maidment, Bill Anderson, Ambassador Gordon Giffin, Kent Jespersen, Yakout Mansour, Steve Snyder*

* *Note: Dawn Farrell replaced Steve Snyder as President and CEO in 2012.*

key performance metrics

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

Availability

Our goal is to achieve consistent 89 – 90 per cent fleet availability.

Availability is a key factor in determining revenue in many of our contracts. Availability is the percentage of time a generating unit is capable of running, regardless of whether or not it is generating electricity. Availability of 100 per cent over an extended period of time is not achievable as all plants require ongoing maintenance and experience, from time to time, unplanned outages.

	2011	2010
Adjusted Availability[1] *(%)*	**88.2**	88.9

1 *Adjusted for economic dispatch at Centralia Thermal. Unadjusted fleet availability was 85.4 per cent.*

Availability in 2011 was just slightly below our target of 89 – 90 per cent primarily due to the unplanned outage at our Genesee 3 Unit and due to the shutdown of Sundance Units 1 and 2 prior to declaring economic destruction. Fleet availability has been adjusted to account for the business decision to economically dispatch Centralia, extending planned outages at the plant to take advantage of lower market prices and purchase power on the open market to fulfill our contract obligations. These outages did not negatively impact our gross margins.

Productivity

Our goal is to offset the impact of inflation on Operations, Maintenance and Administration (OM&A) expenses.

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

	2011	2010
OM&A *($/installed MWh)*	**7.71**	6.75

In 2011 OM&A costs per installed MWh increased as a result of a decrease in installed capacity due to the shutdown of Sundance Units 1 and 2, and due to higher OM&A costs as a result of higher compensation costs associated with favourable results, the write off of certain wind development costs, and costs associated with several productivity initiatives, partially offset by lower costs from the discontinuation of managing the base plant at Poplar Creek.

Sustaining Capital Expenditures & Productivity Capital

Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely over a long period of time.

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

Productivity capital is discretionary and is associated with asset life extensions and investments in our information systems and processes.

	2011	2010
Sustaining capital *($ millions)*	**319**	346
Productivity capital *($ millions)*	**42**	9

Sustaining capital in 2011 was in line with our target of $310 – $365 million.

In 2012, sustaining capital is expected to be higher as a result of increased planned major maintenance on our coal facilities to set them up for end of life. Sustaining capital is expected to return to more normal levels in 2013.

Safety

Our ultimate goal is to achieve zero injury incidents; targeting an Injury Frequency Rate (IFR) of less than 1.0.

Safety is a core value at TransAlta. We measure ourselves against industry-wide standards. IFR measures all fatal, lost time, and medical aid injuries.

	2011	2010
IFR	**0.89**	1.19

We fully delivered on our safety goal in 2011 by achieving an IFR of 0.89, which is one of the best in TransAlta's history. This is the result of continuous efforts to improve safety through improved education and training.

EBITDA, Earnings and Cash Flow

Our goal is to steadily grow comparable EBITDA, comparable EPS, and FFO on a trend line basis over the commodity cycle.

Comparable EBITDA is frequently used to analyze and compare profitability between companies and industries because it eliminates the effects of financing and accounting decisions.

Comparable Earnings Per Share (EPS) is commonly used to measure a company's on-going profitability.

Funds From Operations (FFO) and FFO per share are measures of cash flow. They reflect the cash flow available to maintain our equipment, meet our debt repayment obligations, return capital to shareowners through dividends, and invest in new capacity.

	2011	2010
Comparable EBITDA *($ millions)*	**1,077**	955
Comparable Earnings Per Share *($)*	**1.04**	0.97
Funds From Operations *($ millions)*	**809**	805
Funds From Operations Per Share *($ millions)*	**3.64**	3.68

Comparable EBITDA and comparable EPS increased year-over-year due to strong results from both our Generation and Energy Trading businesses. Generation gross margins benefited significantly from higher margined renewable assets.

FFO increased in 2011 as a result of higher cash EBITDA offset by higher interest expense due to lower capitalized interest from the commissioning of Keephills 3.

FFO per share was slightly below 2010 as a result of more shares issued and outstanding at the end of 2011. In 2011, 3.2 million shares were issued under the dividend reinvestment and share purchase (DRASP) plan.

Investment Ratios

Our goal is to maintain investment grade credit ratings.

Financial strength and flexibility are critical to the company's ability to create value, capitalize on opportunities, and manage industry cyclicality. The long-term ratios and target ranges used to measure our performance include:

Cash flow to interest	4-5x
Cash flow to total debt	20-25%
Debt to invested capital	55-60%

	2011	2010
Cash flow to interest *(times)*	**4.4**	4.6
Cash flow to total debt *(%)*	**20.2**	19.6
Debt to invested capital *(%)*	**52.4**	53.1

In 2011, we strengthened the balance sheet by issuing $275 million of preferred securities in November and approximately $67 million of common equity under our DRASP plan. We also extended our $1.5 billion syndicated credit facility from mid-2012 to mid-2015.

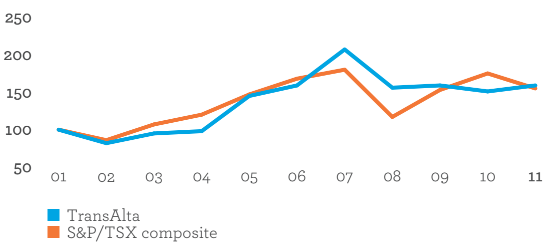
Sustainable Long-Term Shareholder Value

Our goal is to achieve an average Total Shareholder Return (TSR) of 8 – 10 per cent per year over the long-term.

We measure returns to our investors through TSR. TSR is the total amount returned to investors over a specific holding period and includes capital gains or losses and dividends.

	TA 2011	S&P/TSX 2011
TSR *(%)*	**4.9**	**(8.7)**

Total Shareholder Return vs. S&P/TSX Composite Total Return Index
Year ended Dec. 31 ($)



TransAlta has historically tracked and provided total returns in line with the S&P/TSX. While 2011 was below our target of 8 – 10 per cent it was significantly higher than the TSX and we continue to focus on delivering strong shareholder returns.

map of operations

generation facilities

- coal-fired plants
- hydro plants
- gas-fired plants
- wind-powered plants
- geothermal plants
- corporate offices (3)
- energy marketing offices (2)

68 MW Capacity
New Richmond, Quebec, Canada

450 MW Capacity
Keephills 3, Alberta, Canada

As of December 31, 2011	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1]	Fuel	Revenue source	Contract expiry date
Western Canada 39 Facilities	Sundance, AB[2]	1,581	100%	1,581	Coal	Alberta PPA/Merchant[3]	2020
	Keephills, AB[4]	812	100%	812	Coal	Alberta PPA/Merchant[4]	2020
	Keephills 3, AB	450	50%	225	Coal	Merchant	—
	Genesee 3, AB	466	50%	233	Coal	Merchant	—
	Sheerness, AB	780	25%	195	Coal	Alberta PPA	2020
	Poplar Creek, AB	356	100%	356	Gas	LTC/Merchant	2024
	Fort Saskatchewan, AB	118	30%	35	Gas	LTC	2019
	Brazeau, AB	355	100%	355	Hydro	Alberta PPA	2020
	Big Horn, AB	120	100%	120	Hydro	Alberta PPA	2020
	Spray, AB	103	100%	103	Hydro	Alberta PPA	2020
	Ghost, AB	51	100%	51	Hydro	Alberta PPA	2020
	Rundle, AB	50	100%	50	Hydro	Alberta PPA	2020
	Cascade, AB	36	100%	36	Hydro	Alberta PPA	2020
	Kananaskis, AB	19	100%	19	Hydro	Alberta PPA	2020
	Bearspaw, AB	17	100%	17	Hydro	Alberta PPA	2020
	Pocaterra, AB	15	100%	15	Hydro	Alberta PPA	2013
	Horseshoe, AB	14	100%	14	Hydro	Alberta PPA	2020
	Barrier, AB	13	100%	13	Hydro	Alberta PPA	2020
	Taylor Hydro, AB	13	100%	13	Hydro	Merchant	—
	Interlakes, AB	5	100%	5	Hydro	Alberta PPA	2020
	Belly River, AB	3	100%	3	Hydro	Merchant	—
	Three Sisters, AB	3	100%	3	Hydro	Alberta PPA	2020
	Waterton, AB	3	100%	3	Hydro	Merchant	—
	St. Mary, AB	2	100%	2	Hydro	Merchant	—
	Upper Mamquam, BC	25	100%	25	Hydro	LTC	2025
	Pingston, BC	45	50%	23	Hydro	LTC	2023
	Bone Creek, BC	19	100%	19	Hydro	LTC	2031
	Akolkolex, BC	10	100%	10	Hydro	LTC	2015
	Summerview 1, AB	70	100%	70	Wind	Merchant	—
	Summerview 2, AB	66	100%	66	Wind	Merchant	—
	Ardenville, AB	69	100%	69	Wind	Merchant	—
	Blue Trail, AB	66	100%	66	Wind	Merchant	—
	Castle River, AB[5]	44	100%	44	Wind	Merchant	—
	McBride Lake, AB	75	50%	38	Wind	LTC	2023
	Soderglen, AB	71	50%	35	Wind	Merchant	—
	Cowley Ridge, AB	21	100%	21	Wind	Merchant	—
	Cowley North, AB	20	100%	20	Wind	Merchant	—
	Sinnott, AB	7	100%	7	Wind	Merchant	—
	Macleod Flats, AB	3	100%	3	Wind	Merchant	—
	Total Western Canada	**5,996**		**4,775**			
Eastern Canada 14 Facilities	Sarnia, ON	506	100%	506	Gas	LTC	2022-2025
	Mississauga, ON	108	50%	54	Gas	LTC	2017
	Ottawa, ON	68	50%	34	Gas	LTC	2012
	Windsor, ON	68	50%	34	Gas	LTC/Merchant	2016
	Ragged Chute, ON	7	100%	7	Hydro	Merchant	—
	Misema, ON	3	100%	3	Hydro	LTC	2027
	Galetta, ON	2	100%	2	Hydro	LTC	2031
	Appleton, ON	1	100%	1	Hydro	LTC	2031
	Moose Rapids, ON	1	100%	1	Hydro	LTC	2031
	Wolfe Island, ON	198	100%	198	Wind	LTC	2029
	Melancthon, ON	200	100%	200	Wind	LTC	2026-2028
	Le Nordais, QC	99	100%	99	Wind	LTC	2033
	Kent Hills, NB	150	83%	125	Wind	LTC	2033-2035
	New Richmond, QC[6]	68	100%	68	Wind	Quebec PPA	2032
	Total Eastern Canada	**1,479**		**1,332**			
United States 17 Facilities	Centralia, WA	1,340	100%	1,340	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, CA[7]	327	50%	164	Geothermal	LTC	2016-2029
	Skookumchuck, WA	1	100%	1	Hydro	LTC	2020
	Wailuku, HI	10	50%	5	Hydro	LTC	2023
	Total U.S.	**2,428**		**1,979**			
Australia 5 Facilities	Parkeston, WA	110	50%	55	Gas	LTC	2016
	Southern Cross, WA[8]	245	100%	245	Gas/Diesel	LTC	2013
	Total Australia	**355**		**300**			
TOTAL		**10,258**		**8,386**			

1 *Megawatts are rounded to the nearest whole number.*
2 *Includes a 15 MW uprate on Sundance Unit 3 expected to be commercial in 2012; excludes Sundance Units 1 and 2.*
3 *Merchant capacity refers to uprates on Unit 4 (53 MW), Unit 5 (53 MW), and Unit 6 (44 MW).*
4 *Includes two 23 MW uprates on Keephills Units 1 and 2 expected to be commercial in 2012 as merchant capacity.*
5 *Includes seven individual turbines at other locations.*
6 *Facilities currently under development.*
7 *Comprised of 10 facilities.*
8 *Comprised of four facilities.*

management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited 2011 consolidated financial statements and our 2012 Annual Information Form. On Jan. 1, 2011, we adopted International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises. Prior to the adoption of IFRS, we followed Canadian Generally Accepted Accounting Principles ("Canadian GAAP" or our "previous GAAP"). All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted. This MD&A is dated March 1, 2012. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or "the Corporation"), including our Annual Information Form, is available on SEDAR at **www.sedar.com**, or EDGAR at **www.sec.gov**, 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. 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, and geothermal. During 2011, we began commercial operations at our Keephills Unit 3 coal-fired plant and our Bone Creek hydro facility, which added 244 megawatts ("MW") of power to our generation portfolio and increased our total generating capacity to 8,174 MW.

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 Western U.S., 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 annual rate of one to three per cent. During the recession in 2008 and 2009 demand decreased in the Pacific Northwest and Ontario an average of two and four per cent, respectively, and stayed flat in Alberta. Demand growth has returned, although at varying rates among Alberta, the Pacific Northwest, and Ontario.

After flat demand in Alberta from 2007 to 2009, 2010 and 2011 showed a return to about three per cent annual growth. In Alberta, investment in oil sands development is a key driver of electricity demand growth, and high oil prices are currently driving a major expansion of this resource. In the Pacific Northwest, demand recovered in 2011 by approximately three per cent after decreasing in 2010, although we believe approximately half of the growth in 2011 was due to unseasonable weather. Demand in Ontario increased in 2010 and 2011 at an average rate of around one per cent annually.

Supply

Reserve margins, which measure available capacity in a market over and above the capacity needed to meet normal peak demand levels, declined in Alberta, the Pacific Northwest, and Ontario in 2011.

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 Pacific Northwest currently has just over 5,000 MW of wind capacity after adding approximately 2,300 MW from 2009 to 2011 and Ontario has been developing wind and solar capacity through its Feed in Tariff program. Wind generation in Alberta has also grown significantly in the last few years.

Transmission

Transmission refers to the bulk delivery system of power and energy between generating units and wholesale and/or retail customers. Power lines serve as the physical path, transporting electricity from generating units to customers. Transmission systems are designed with reserve capacity to allow for an amount of "real-time" fluctuations in both energy supply and demand caused by generation plants or loads increasing or decreasing output or consumption.

Transmission capacity refers to the ability of the transmission line, or lines, to safely and reliably transport electricity in an amount that balances the dispatched generating supply with demand, and allows for contingency situations on the system. Most transmission businesses in North America are still regulated.

In the North American market, we believe investment in transmission capacity has not kept pace with the growth in demand for electricity. Lead times in new transmission infrastructure projects are significant, subject to extensive consultation processes with landowners, and subject to regulatory requirements that can change frequently. As a result, existing generation or additions of generating capacity may not have ready access to markets until key bulk transmission upgrades and additions are completed.

In 2009, the Government of Alberta declared several important transmission projects as being critical, including lines between the Edmonton and Calgary regions, and between Edmonton and northeast Alberta. In late 2011, the Government of Alberta initiated a review of critical transmission projects. The results of the review by an independent panel were released in early 2012 and the panel recommends proceeding as soon as possible with development of two high-voltage direct current transmission lines between the Edmonton and Calgary regions. The provincial government is reviewing the panel's recommendation.

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 Greenhouse Gas ("GHG") legislation in Alberta. Our exposure to increased costs as a result of environmental legislation in Alberta is mitigated through change-in-law provisions in our Power Purchase Arrangements ("PPAs"). In the State of Washington, the TransAlta Energy Bill was signed into law and provides a framework to transition from coal. Legislation in other jurisdictions is in various stages of maturity and sophistication.

While Carbon Capture and Storage ("CCS") technologies are being developed, these technologies require large-scale demonstration. Project Pioneer, our CCS project, continues to progress with the financial support of industry partners and the Canadian and Alberta governments. This investment is intended to determine whether the cost of CCS can be reduced over the next 10 years in order to assess if CCS is viable from a business perspective.

Economic Environment

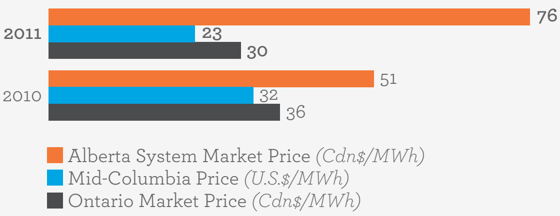
The economic environment showed signs of improvement in 2011 and we expect this trend to continue in 2012 at a slow to moderate pace. We continue to monitor global events, including conditions in Europe, and their potential impact on the economy and our supplier and commodity counterparty relationships.

Contracted Cash Flows

During the year, approximately 93 per cent of our consolidated power portfolio was contracted through the use of PPAs, long-term, and short-term contracts. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2011 ranging from $65 to $70 per megawatt hour ("MWh") in Alberta, and from U.S.$50 to $55 per MWh in the Pacific Northwest.

Electricity Prices

Average Spot Electricity Prices



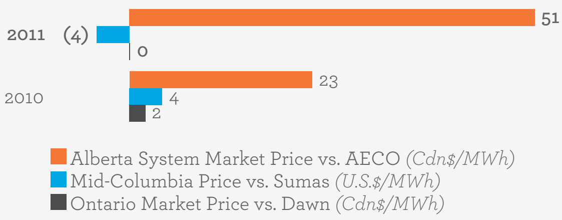
Spot electricity prices are important to our business as our merchant natural gas, wind, hydro, and thermal facilities are exposed to these prices. Changes in these prices will affect our profitability, economic dispatching, and any contracting strategy. Our Alberta plants, operating under PPAs, receive contracted capacity payments based on targeted availability and will pay penalties or receive payments for production outside targeted availability based upon a rolling 30-day average of spot prices. The PPAs and long-term contracts covering a number of our generating facilities help 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.

For the year ended Dec. 31, 2011, average spot prices increased in Alberta due to load growth from the prior year and supply tightening in the market. In the Pacific Northwest and Ontario, average spot prices decreased compared to 2010 due to lower natural gas prices and increased hydro generation in both regions.

Spark Spreads

Average Spark Spreads[1]



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

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 plants due to their design, geographical region in which they operate, and customer and/or market requirements. The change in the prices of electricity and natural gas, and the resulting spark spreads in our three major markets, affect our Generation and Energy Trading Segments.

For the year ended Dec. 31, 2011, average spark spreads increased in Alberta due to higher power prices. In the Pacific Northwest, average spark spreads decreased due to strong hydro generation, which caused power prices to decrease more than natural gas prices compared to 2010. In Ontario, spark spreads decreased as power prices weakened more than natural gas prices.

Strategy

Our goals are to deliver shareholder value by delivering solid returns through a combination of dividend yield, and disciplined comparable Earnings Per Share ("EPS")[2] and funds from operations[2] growth, while maintaining a low to moderate risk profile, balancing capital allocation, and maintaining financial strength. Our comparable EPS and funds from operations growth are driven by optimizing and diversifying our portfolio, growing our renewable portfolio across Canada, and further expanding our overall portfolio and operations in the western regions of Canada, the U.S., and Australia. 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 financial position and investment grade credit ratings to provide a solid foundation for our long-cycle, capital-intensive, and commodity-sensitive business. A strong financial position 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 Strategy

In 2011, we continued to see some demand growth and prices in our key markets improved from the lower prices experienced in 2010 primarily due to supply tightening in the market. While we are not immune to lower power prices, the impact of these lower prices is expected to be mitigated as approximately 86 per cent of 2012 and approximately 77 per cent of 2013 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 stable and predictable operations that are comparatively low cost and balanced with our fleet availability target. Our target for 2012 is to increase productivity and achieve overall fleet availability of 89 to 90 per cent. Over the last two years, our average adjusted availability has been 88.6 per cent, which is slightly below our corporate target.

2 Comparable EPS and funds from operations are not defined under IFRS. 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-IFRS Measures section of this MD&A for further discussion of these items, including reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

Growth Strategy

During 2011, commercial operations began at Keephills Unit 3, one of Canada's largest and cleanest coal-fired facilities which we believe is one of the most advanced facilities of its kind in the world. Emissions per MW are lower than those from a conventional coal plant because less fuel is used to produce the same amount of power. This facility is an important step in ensuring future power needs are met with a reliable, cost-effective and environmentally responsible source of electricity.

Our growth strategy is also focused upon greening and diversifying our portfolio to reduce our carbon footprint and develop long-term, sustainable power generation in our core markets. We furthered this strategy in 2011 by completing our Bone Creek hydro facility on time and on budget and commencing construction of the 68 MW New Richmond wind farm. We continue to explore and selectively develop opportunities for future sustainable power projects.

Capability to Deliver Results

We have the following core competencies and non-capital resources that give us the capability to achieve our corporate objectives. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of the capital resources available that will assist us in achieving 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 Strategic Focus Areas in 2011

Improve base operations	• Began commercial operations at Keephills Unit 3 • Implemented productivity and cost reductions that lowered operating expenses across the fleet • Continued to align plans and capital spending for coal units based on the proposal to reduce GHG emissions by their 45th year of operation
Reposition coal	• Continued active involvement in environmental policy discussions with various levels of government in Canada and the U.S.
Green and diversify our portfolio	• Added 19 MW of hydro generation to our portfolio by completing construction of the Bone Creek hydro facility • Continued our work on the construction of New Richmond, a 68 MW wind farm in Quebec

Financial Strength

We manage our financial position and cash flows to maintain financial strength and flexibility throughout all economic cycles. This financial discipline proved valuable during the weak economic environment of 2011 and will continue to be important during 2012. We continue to maintain $2.0 billion in committed credit facilities, and as of Dec. 31, 2011, $0.9 billion was available to us. Our investment grade credit rating, available credit facilities, funds from operations, and our limited debt maturity profile provide us with financial flexibility. As a result we can be selective as to 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 2011, we took advantage of favourable capital markets by completing the sale of $275 million of Series C Preferred Shares. Looking forward, we expect 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 and meeting our liquidity requirements, base business investment, and growth opportunities. We believe we have a proven track record of maintaining our long-term financial stability, which includes balancing the cash distributions to our shareholders through dividends with making investments in growth projects that will deliver long-term cash flow.

We continue to selectively grow our diversified generating fleet in order to increase production and meet future demand requirements, with growth projects that have the ability to meet or exceed our targeted rate of return. We currently have 68 MW of wind generation under construction and 61 MW of uprates to our thermal coal fleet planned for 2012. We also have more than 2,600 MW of advanced development wind, hydro, natural gas, and geothermal projects in our development pipeline.

People

Our experienced leadership team is made up 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 energy business, in our opinion, has resulted in a long-term proven track record of financial stability.

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

1 *Adjusted for economic dispatching at Centralia.*

We strive to optimize the availability of our plants 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, as well as by 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 in order to balance our maintenance costs with optimal availability targets. Over the past two years, we have achieved an average adjusted availability of 88.6 per cent, which is slightly below our long-term target of 89 to 90 per cent. Our adjusted availability in 2011 was 88.2 per cent.

Availability for the year ended Dec. 31, 2011 decreased compared to 2010 primarily due to higher planned and unplanned outages at Centralia Thermal and higher unplanned outages at Genesee Unit 3, partially offset by lower planned and unplanned outages at the Alberta coal PPA facilities and lower planned outages at Genesee Unit 3.

The outages at Centralia Thermal did not negatively impact our gross margins for the year ended Dec. 31, 2011 as we were able to extend our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

Productivity

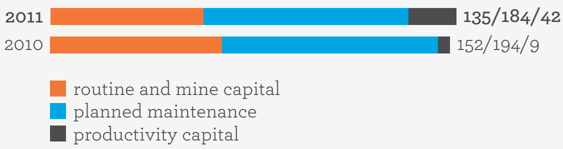
OM&A
($/installed MWh)

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, 2011, OM&A costs per installed MWh increased compared to 2010 due to higher compensation costs associated with favourable results in the Energy Trading Segment, the writeoff of certain wind development costs and costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

Sustaining Capital Expenditures

Sustaining Capital Expenditures
($ millions)



We are in a long-cycle capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely over a long period of time. Our sustaining capital is comprised of three components: (1) routine and mine capital, (2) planned maintenance, and (3) productivity capital.

In 2011, we spent $6 million more on sustaining capital expenditures compared to 2010, which was made up of $33 million more on productivity capital, $17 million less on routine and mine capital, and $10 million less on planned maintenance. The decrease in routine and mine capital was due to lower information technology capital and non-turnaround maintenance costs as well as a decrease in mine capital due to lower land costs. Planned maintenance decreased primarily due to fewer major coal outages due to the shut down of Sundance Units 1 and 2, partially offset by higher gas plant outages. The increase in productivity expenditures was primarily due to instrument and controls projects at the Keephills and Sundance facilities, site improvements at our Sundance facility, and the implementation of new software programs.

Safety

Safety is our top priority with all of our staff, contractors, and visitors. Our objective is to improve safety by reducing our Injury Frequency Rate ("IFR") to 0.5 by 2015. Our ultimate goal is to achieve zero injury incidents.

	2011	2010
IFR	**0.89**	1.19

In 2011, our IFR decreased due to fewer injuries at our Alberta coal facilities, primarily at our Keephills and Sundance facilities. These improvements are a result of continuous efforts to enhance our safety programs through near miss reporting, safety improvement, education, and awareness.

Earnings and Funds From Operations

We focus our base business on delivering strong earnings and funds from operations growth. Our goal is to steadily grow comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA")[1], comparable EPS, and funds from operations, over the long term, recognizing that the amount of growth may fluctuate year over year with the commodity cycle.

	2011	2010
Comparable EBITDA	**1,077**	955
Comparable EPS	**1.04**	0.97
Funds from operations	**809**	805
Funds from operations per share[1]	**3.64**	3.68

1 *Comparable EBITDA and funds from operations per share are not defined under IFRS. Presenting these items 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-IFRS Measures section of this MD&A for further discussion of these items, including reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.*

In 2011, comparable EPS and comparable EBITDA increased compared to 2010 primarily due to higher comparable earnings.

In 2011, funds from operations increased compared to 2010 due to higher net earnings.

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 financial position and cash flow coverage ratios to support stable investment grade credit ratings.

	2011	2010
Cash flow to interest coverage *(times)*	**4.4**	4.6
Cash flow to debt *(%)*	**20.2**	19.6
Debt to invested capital *(%)*	**52.4**	53.1

Cash flow to interest coverage decreased in 2011 compared to 2010 primarily due to lower capitalized interest. Our goal is to maintain this ratio in a range of four to five times.

Cash flow to debt improved in 2011 compared to 2010 due to lower average debt levels in 2011. Our goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital decreased as at Dec. 31, 2011 compared to 2010 due to lower debt levels and higher net earnings. Our goal is to maintain this ratio in a range of 55 to 60 per cent.

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 goal is to grow Total Shareholder Return ("TSR")[2] by achieving a return of eight to 10 per cent per year over the long-term, with four to five per cent resulting from yield and four to five per cent resulting from growth.

The table below shows our historical performance on this measure:

	2011	2010
TSR *(%)*	**4.9**	(5.0)

While 2011 was below our target of eight to 10 per cent, we continue to focus on delivering strong shareholder returns.

2 *This measure is not defined under IFRS. We evaluate our performance and the performance of our business segments using a variety of measures. This measure is not necessarily comparable to a similarly titled measure of another company. TSR is the total amount returned to investors over a specific holding period and includes capital gains, capital losses, and dividends.*

Results of Operations

Our results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading and Corporate. Some of our accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Some of our critical accounting policies and estimates include: revenue recognition, valuation and useful life of Property, Plant, and Equipment ("PP&E"), financial instruments, decommissioning and restoration provisions, 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 Statements of Financial Position. While individual line items on the Consolidated Statements of Financial Position will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to foreign operations is reflected in the equity section of the Consolidated Statements of Financial Position.

Highlights and Summary of Results

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

Year ended Dec. 31	**2011**	2010	2009 [1]
Availability *(%)* [2]	**85.4**	88.9	85.1
Production *(GWh)* [2]	**41,012**	48,614	45,736
Revenues	**2,663**	2,673	2,770
Gross margin [3]	**1,716**	1,488	1,542
Operating income [3]	**662**	487	378
Net earnings attributable to common shareholders	**290**	255	181
Net earnings per share attributable to common shareholders, basic and diluted	**1.31**	1.16	0.90
Comparable earnings per share	**1.04**	0.97	0.90
Comparable EBITDA	**1,077**	955	888
Funds from operations	**809**	805	580
Funds from operations per share	**3.64**	3.68	2.89
Cash flow from operating activities	**694**	838	729
Free cash flow [3]	**181**	172	(117)
Dividends paid per common share	**1.16**	1.16	1.16

1 Canadian GAAP figures.
2 Availability and production includes all generating assets (generation operations, finance lease, and equity investments).
3 Gross margin, operating income and free cash flow are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

As at Dec. 31	**2011**	2010
Total assets	**9,760**	9,635
Total long-term liabilities	**4,942**	5,009

Net Earnings Attributable to Common Shareholders

The primary factors contributing to the change in net earnings attributable to common shareholders for the year ended Dec. 31, 2011 are presented below:

Net earnings attributable to common shareholders for the year ended Dec. 31, 2010	255
Increase in Generation gross margins	54
Mark-to-market movements – Generation	78
Increase in Energy Trading gross margins	96
Increase in OM&A costs	(35)
Increase in depreciation expense	(18)
Increase in gain on sale of assets	16
Decrease in asset impairment charges	11
Increase in net interest expense	(37)
Increase in equity earnings	7
Increase in income taxes expense	(82)
Increase in net earnings attributable to non-controlling interests	(14)
Increase in preferred share dividends	(14)
Increase in reserve on collateral	(18)
Other	(9)
Net earnings attributable to common shareholders for the year ended Dec. 31, 2011	**290**

For the year ended Dec. 31, 2011, Generation gross margins, excluding the impact of mark-to-market movements, increased compared to 2010 primarily due to higher hydro margins, the commencement of commercial operations of Keephills Unit 3 in 2011, higher wind volumes, lower planned and unplanned outages at the Alberta coal PPA facilities, and lower planned outages at Genesee Unit 3, partially offset by lower recoveries from the Poplar Creek base plant that we no longer operate, the sale of the Meridian facility, unfavourable pricing related to penalties paid under Alberta PPAs during outages, the decommissioning of Wabamun, and higher unplanned outages at Genesee Unit 3. The lower recoveries at the Poplar Creek base plant were offset by lower OM&A costs.

Mark-to-market movements increased for the year ended Dec. 31, 2011 compared to 2010 due to the recognition of unrealized gains resulting from certain hedges being deemed ineffective for accounting purposes and increased weakening in market prices in the Pacific Northwest relative to our hedged prices.

For the year ended Dec. 31, 2011, Energy Trading gross margins increased compared to 2010 primarily due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

OM&A costs increased for the year ended Dec. 31, 2011 compared to 2010 due to higher compensation costs primarily associated with favourable results in the Energy Trading Segment, the writeoff of certain wind development costs and costs associated with several productivity initiatives, partially offset by lower costs associated with the discontinuation of managing the base plant at Poplar Creek.

For the year ended Dec. 31, 2011, depreciation expense increased compared to 2010 primarily due to an increased asset base, the impact of the 2010 decrease in Wabamun decommissioning and restoration costs, and the writedown of capital spares, partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Gain on sale of assets for the year ended Dec. 31, 2011 increased compared to 2010 due to the sale of the Meridian gas facility, the Grande Prairie biomass facility, and other development projects.

Asset impairment charges for the year ended Dec. 31, 2011 decreased compared to 2010 due to impairment charges related to Sundance Units 1 and 2 and the Meridian facility recorded in 2010. Refer to the Asset Impairment Charges section of this MD&A for further discussion.

For the year ended Dec. 31, 2011, net interest expense increased compared to 2010 due to lower capitalized interest, lower interest income related to the resolution of certain tax matters in 2010, and higher interest rates, partially offset by favourable foreign exchange rates and lower debt levels.

Equity earnings increased for the year ended Dec. 31, 2011 compared to 2010 primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

For the year ended Dec. 31, 2011, income tax expense increased compared to 2010 due to higher earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

Net earnings attributable to non-controlling interests increased for the year ended Dec. 31, 2011 compared to 2010 due to higher earnings at TransAlta Cogeneration, L.P. ("TA Cogen").

The preferred share dividends for year ended Dec. 31, 2011 increased compared to 2010 due to a higher balance of preferred shares outstanding during 2011. Preferred shares were issued in the fourth quarter of 2010 and there was an additional issuance in the fourth quarter of 2011.

A reserve on collateral was taken in the fourth quarter of 2011 related to collateral on hand at MF Global Inc. In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. The reserve was recognized due to the uncertainty of collection of the collateral.

Significant Events

Our consolidated financial results include the following significant events:

2011

Sale of Preferred Shares

On Nov. 30, 2011, we completed our public offering of 11 million Series C 4.60 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $275 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Genesee Unit 3 Outage

On Nov. 11, 2011, the Genesee Unit 3 plant, a 466 MW joint venture with Capital Power Corporation ("Capital Power") (233 MW net ownership interest), experienced an unplanned outage that resulted in damage to the turbine/generator bearings. Genesee Unit 3 returned to service on Jan. 15, 2012.

MF Global Inc.

In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which we used as a broker-dealer for certain commodity transactions. MF Global Inc. has not filed for bankruptcy but, under the U.S. Securities Investor Protection Act, the Securities Investor Protection Corp. is overseeing a liquidation of the broker-dealer to return assets to customers. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of our collateral relates to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and is subject to a dispute between the U.S. trustee and the U.K. administrator. We have collateral of approximately $36 million with MF Global Inc. and due to the uncertainty of collection, we have recognized an $18 million reserve against the collateral that had been posted. The net amount of the collateral has been reclassified to a long-term asset.

Keephills Unit 3

On Sept. 1, 2011, our 450 MW Keephills Unit 3 thermal facility, of which we have a 50 per cent ownership interest, began commercial operations. The total cost of the project was approximately $1.98 billion.

Sale of Grande Prairie Facility

On July 27, 2011, we signed an agreement to sell our interest in the biomass facility located in Grande Prairie. This deal closed on Oct. 1, 2011. As a result, we realized a pre-tax gain of $9 million in the fourth quarter of 2011.

President and Chief Executive Officer

On July 27, 2011, we announced that TransAlta's President and Chief Executive Officer Steve Snyder would retire, effective Jan. 1, 2012. Dawn Farrell, TransAlta's Chief Operating Officer, succeeded Mr. Snyder as President and Chief Executive Officer on Jan. 2, 2012.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 of our Sundance facility due to the mechanical failure of critical generator components. In response to this event, we gave notice of a High Impact Low Probability ("HILP") event and claimed force majeure relief under the PPA. Since the event, we have recorded an after-tax charge of $16 million, or 50 per cent of the penalties, as calculated under the PPA, pending a resolution of this matter.

On Oct. 20, 2010, the Balancing Pool confirmed our determination that the mechanical failure met the requirements of a HILP event under the PPA. On July 5, 2011, the Balancing Pool purported to rescind its earlier determination. Neither action is a conclusive finding of a force majeure event, nor does either provide a definitive resolution to the dispute. Management continues to be of the view that the event constitutes both a HILP and force majeure and that it will be resolved in TransAlta's favour, although no assurance can be given as to the outcome of this matter. The arbitration hearing has been set for May 2012. In the event of an unfavourable resolution of this matter, we may be required to pay to the PPA Buyers the penalties as calculated under the PPA and record an additional $16 million charge to earnings. There is no additional impact to earnings at this time as the facility is operating at full capacity. The unit may be operated in that manner for as long as our monitoring indicates that it can be operated safely, subject to the terms of the agreement, market conditions, and other operating requirements. The previously announced major maintenance at this facility remains scheduled for the middle of 2012.

Bone Creek

On June 1, 2011, our 19 MW Bone Creek hydro facility began commercial operations. The total capital cost of the project was approximately $52 million.

Centralia Coal

In 2011, the TransAlta Energy Bill (the "Bill") was signed into law in the State of Washington. The Bill, and a Memorandum of Agreement (the "MoA") signed on Dec. 23, 2011, which is part of the Bill, provide a framework to transition from coal-fired energy produced at our Centralia Coal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of the shut down of the units and the removal of restrictions on the terms of power contracts that we can enter into.

At Dec. 31, 2011, we completed an assessment of whether the carrying amount of the Centralia Coal plant was recoverable from the future cash flows expected to be derived from the plant's operations. Based on this assessment, which included assumptions regarding our ability to enter into power contracts longer than five years as permitted in the Bill and MoA, we concluded that the plant was not impaired.

However, given the significance of the contracting assumptions, it is possible that actual outcomes could differ from these assumptions and that a material adjustment to the $786 million carrying amount of the plant could arise within the next fiscal year.

We have established a dedicated commercial team to pursue long-term contracts for the plant, and as a result, we expect to be able to more clearly determine the impact of this uncertainty on the future cash flows of the plant in 2012. If we achieve our long-term contracting targets for the plant in 2012, we do not expect that an impairment loss will result.

Sale of Meridian

On Dec. 20, 2010, TA Cogen, a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. On April 1, 2011, TA Cogen closed the sale of its interest in the Meridian facility. The sale was effective Jan. 1, 2011. As a result, we realized a pre-tax gain of $3 million during the second quarter of 2011.

New Richmond

On March 28, 2011, we announced that we had received approval from the Government of Quebec to proceed with the construction of the 68 MW New Richmond wind project located on the Gaspé Peninsula. New Richmond is contracted under a 20-year Electricity Supply Agreement with Hydro-Québec Distribution. The cost of the project is estimated to be approximately $205 million and commercial operations are expected to commence during the fourth quarter of 2012.

Sundance Units 1 and 2 Shut Down

In December 2010, Unit 1 and Unit 2 of our Sundance coal-fired generation facility were shut down due to conditions observed in the boilers at both units. As a result, all 560 MW from both units, with potential production of 4,906 gigawatt hours ("GWh"), was unavailable for the year ended Dec. 31, 2011.

We are pursuing all our remedies under the PPA resulting from these events. Firstly, under the terms of the PPA for these units, we notified the PPA Buyer and the Balancing Pool of a force majeure event. To the extent the event meets the force majeure criteria set out in the PPA, we believe we are entitled to receive our PPA capacity payments and are protected from having to pay penalties for the units' lack of availability, and as a result, we do not expect any material adverse effect on our results or operations. Secondly, on Feb. 8, 2011, we issued a notice of termination for destruction on Sundance Units 1 and 2 under the terms of the PPA. This action was based on the determination that the physical state of the boilers was such that the units cannot be economically restored to service under the terms of the PPA. To the extent the event meets the termination for destruction criteria set out in the PPA, we believe we are entitled to recover the net book value specified in the PPA, and as a result, we do not expect any material financial impact.

On Feb. 18, 2011, the PPA Buyer provided notice that it intends to dispute the notice of force majeure and termination for destruction, and intends to pursue the dispute resolution process as set out under the terms of the PPA. The binding arbitration process to resolve the dispute is underway. The arbitration panel identified dates in March and April 2012 to hear these claims, and unless timelines are shortened by agreement of the parties, indicated that its decision would be forthcoming in mid-2012. No assurance can be given as to the timing or ultimate outcome of these matters.

Change in Estimated Residual Values

During the first quarter of 2011, management completed a comprehensive review of the residual values of all of our generating assets, having regard for, among other things, expectations about the future condition of the assets, metal volumes, as well as other market-related factors. As a result, estimated residual values were revised, resulting in depreciation decreasing by $13 million for the year ended Dec. 31, 2011 compared to 2010.

2010

Allocation of Consideration Transferred Adjustment

During the fourth quarter of 2010, management updated the preliminary allocation of consideration transferred related to our acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro") to better reflect the value of the underlying assets and liabilities acquired. As a result, a $114 million adjustment was made to depreciable assets, producing a $4 million decrease in depreciation expense. The adjustment to depreciable assets was offset by adjustments to goodwill and deferred income taxes.

Resolution of Tax Matters

During 2010, we recognized and received a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense also decreased by $14 million as a result of tax-related interest recoveries.

Sale of Preferred Shares

On Dec. 10, 2010, we completed our public offering of 12 million Series A 4.60 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $300 million. The net proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation and its affiliates.

Kent Hills 2

On Nov. 21, 2010, the 54 MW expansion of our Kent Hills wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $100 million. Natural Forces Technologies, Inc. ("Natural Forces") exercised its option to purchase a 17 per cent interest in the Kent Hills 2 project subsequent to the commencement of commercial operations for proceeds of $15 million based on costs incurred in 2010. The pre-tax gain recorded related to this transaction did not have a significant impact on net earnings.

Ardenville

On Nov. 10, 2010, our 69 MW Ardenville wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was approximately $135 million.

Project Pioneer

On Nov. 28, 2010, we announced that the Global Carbon Capture and Storage Institute awarded the Corporation AUD$5 million to share knowledge around the world from Project Pioneer, Canada's first fully integrated CCS project involving retrofitting a coal-fired generation plant. The funding will help Project Pioneer both contribute to and access international research and leading-edge knowledge from a global CCS forum.

On June 28, 2010, we announced that Enbridge Inc. will officially participate as a partner in the development of Project Pioneer.

Sundance Unit 3 Uprate

On Sept. 13, 2010, we obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of our Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed Chief Financial Officer, succeeding Brian Burden, who retired from the Corporation. Mr. Burden assisted Mr. Gellner with the transition through Sept. 30, 2010.

Dividend Reinvestment and Share Purchase ("DRASP")

On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. Under the terms of our DRASP plan, eligible participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. The Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

Decommissioning of Wabamun Plant

On March 31, 2010, we fully retired all units of the Wabamun plant as part of our previously announced shut down. Over the next several years, we will complete the Wabamun plant remediation and reclamation work as approved by the Government of Alberta. Based on our review of our schedule and detailed costing of the decommissioning and reclamation activities, the decommissioning and reclamation obligation associated with the Wabamun plant was reduced by $14 million during the first quarter of 2010, with the offset recorded as a recovery in depreciation.

Senior Notes Offering

On March 12, 2010, we completed our offering of U.S.$300 million senior notes maturing in 2040 and bearing an interest rate of 6.50 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

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 approximately $118 million.

Change in Economic Useful Life

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, our economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to 2009.

Subsequent Events

Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan

On Feb. 21, 2012, we announced that we added a Premium Dividend™ Component to our existing DRASP plan. The amended and restated plan is called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan"). The Plan provides our eligible shareholders with two options, to reinvest dividends at a current three per cent discount towards the purchase of new shares of TransAlta or instead, to receive the equivalent to 102 per cent of the dividends payable in cash. The discount on reinvested dividends can be adjusted to between zero to five per cent at the discretion of the Board of Directors.

Eligible shareholders are not required to participate in the Plan. Those shareholders who have not elected or been deemed to have elected to participate in the Plan will continue to receive their quarterly cash dividends in the usual manner. To participate in the Plan, eligible shareholders must be resident in Canada. Residents of the U.S., or an individual who is otherwise a "U.S. Person" under applicable U.S. securities laws, may not participate in the Plan. Shareholders who are resident in any jurisdiction outside of Canada (other than the U.S.) may participate in the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that we are satisfied, in our sole discretion, that such laws do not subject the Plan, TransAlta, the Plan Agent, or the Plan Broker to additional legal or regulatory requirements.

Discussion of Segmented Results

GENERATION: Owns and operates hydro, wind, natural gas- and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support.

We have strategic alliances with Stanley Power Inc. ("Stanley Power"), Capital Power, ENMAX Corporation ("ENMAX"), MidAmerican Energy Holdings Company ("MidAmerican"), Nexen Inc. ("Nexen"), and Brookfield Asset Management Inc. ("Brookfield"). Stanley Power owns the minority interest in TA Cogen. The Capital Power alliance provided the opportunity for us to acquire 50 per cent ownership in the 466 MW Genesee 3 project, as well as to build the Keephills Unit 3 project. ENMAX and our Corporation each own 50 per cent of 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.

Due to our transition to IFRS, our interest in the Fort Saskatchewan generating facility is now accounted for as a finance lease and our interests in the CE Gen and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures are now accounted for using the equity method. Accordingly, the related operational and financial results of these facilities are no longer included in the results of our Western Canada and International geographical regions, respectively. Under Canadian GAAP, these assets were proportionately consolidated. Although these assets no longer contribute to the operating income of the Generation Segment for accounting purposes, it is management's view that these facilities still form part of our Generation Segment. Refer to the Finance Lease and Equity Investments sections of the Generation Segment discussion of this MD&A for further details.

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.

Generation Operations

At Dec. 31, 2011, Generation Operations had 8,174 MW of gross generating capacity[1] in operation (7,831 MW net ownership interest) and 129 MW (net ownership interest) under construction. The following information excludes assets that are accounted for as a finance lease or using the equity method, which are discussed separately within the discussion of the Generation Segment. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary.

During 2011, we began commercial operations at our Keephills Unit 3 coal-fired plant and our Bone Creek hydro facility, which added 244 MW of power to our generation portfolio. Refer to the Significant Events section of this MD&A for further discussion.

The results of Generation Operations are as follows:

Year ended Dec. 31	**2011**				2010	
	Total	**Comparable adjustments** [2]	**Comparable total** [2]	**Per installed MWh**	Comparable total [2]	Per installed MWh
Revenues	**2,526**	**(127)**	**2,399**	**33.94**	2,589	34.26
Fuel and purchased power	**947**	**-**	**947**	**13.40**	1,185	15.68
Gross margin	**1,579**	**(127)**	**1,452**	**20.54**	1,404	18.58
Operations, maintenance, and administration	**419**	**(6)**	**413**	**5.84**	424	5.61
Depreciation and amortization	**460**	**(4)**	**456**	**6.45**	443	5.86
Taxes, other than income taxes	**27**	**-**	**27**	**0.38**	27	0.36
Intersegment cost allocation	**8**	**-**	**8**	**0.11**	5	0.07
Operating expenses	**914**	**(10)**	**904**	**12.78**	899	11.90
Operating income	**665**	**(117)**	**548**	**7.76**	505	6.68
Installed capacity *(GWh)*	**70,681**		**70,681**		75,559	
Production *(GWh)*	**38,911**		**38,911**		46,416	
Availability *(%)*	**84.8**		**84.8**		88.5	

2 Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

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

Generation Production and Comparable Gross Margins[1]

Generation's production volumes, comparable revenues[1], fuel and purchased power costs, and comparable gross margins[1] based on geographical regions and fuel types are presented below.

Year ended Dec. 31, 2011	Production (GWh)	Installed (GWh)	Revenue[2]	Fuel & purchased power	Gross margin[2]	Revenue per installed MWh[2]	Fuel & purchased power per installed MWh	Gross margin per installed MWh[2]
Coal	21,475	26,846	863	379	484	32.15	14.12	18.03
Gas	2,588	3,282	118	33	85	35.95	10.05	25.90
Renewables	3,237	11,645	220	11	209	18.89	0.94	17.95
Total Western Canada	27,300	41,773	1,201	423	778	28.75	10.13	18.62
Gas	3,578	6,570	410	219	191	62.40	33.33	29.07
Renewables	1,521	5,790	147	7	140	25.39	1.21	24.18
Total Eastern Canada	5,099	12,360	557	226	331	45.06	18.28	26.78
Coal	5,135	11,742	520	261	259	44.29	22.23	22.06
Gas	1,377	4,806	121	37	84	25.18	7.70	17.48
Total International	6,512	16,548	641	298	343	38.74	18.01	20.73
	38,911	70,681	2,399	947	1,452	33.94	13.40	20.54

2 Amounts represent comparable figures.

Year ended Dec. 31, 2010	Production (GWh)	Installed (GWh)	Revenue[3]	Fuel & purchased power	Gross margin[3]	Revenue per installed MWh[3]	Fuel & purchased power per installed MWh	Gross margin per installed MWh[3]
Coal	25,025	31,325	813	331	482	25.95	10.57	15.38
Gas	3,493	4,246	222	76	146	52.28	17.90	34.38
Renewables	2,506	11,120	142	10	132	12.77	0.90	11.87
Total Western Canada	31,024	46,691	1,177	417	760	25.21	8.93	16.28
Gas	3,816	6,570	435	243	192	66.21	36.99	29.22
Renewables	1,330	5,435	126	7	119	23.18	1.29	21.89
Total Eastern Canada	5,146	12,005	561	250	311	46.73	20.82	25.91
Coal	8,594	12,057	730	469	261	60.55	38.90	21.65
Gas	1,652	4,806	121	49	72	25.18	10.20	14.98
Total International	10,246	16,863	851	518	333	50.47	30.72	19.75
	46,416	75,559	2,589	1,185	1,404	34.26	15.68	18.58

3 Amounts represent comparable figures.

Western Canada

Our Western Canada assets consist of five coal plants, one natural gas-fired facility, 21 hydro facilities, and 11 wind farms, with a total gross generating capacity of 4,874 MW (4,678 MW net ownership interest). In 2011, we began commercial operations at Keephills Unit 3, a 450 MW (225 MW net ownership interest) coal-fired plant in Alberta, and Bone Creek, a 19 MW hydro facility in British Columbia. We are currently performing uprates of 23 MW each on Unit 1 and Unit 2 of our Keephills plant, and a 15 MW uprate on Unit 3 of our Sundance plant, which are scheduled to be completed by the third quarter, second quarter, and fourth quarter of 2012, respectively.

Our Sundance, Keephills Units 1 and 2, and Sheerness plants, and 14 hydro facilities with gross generating capacity of 4,103 MW (3,907 MW net ownership interest) operate under PPAs. 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.

1 Comparable figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders and cash flow from operating activities.

Genesee Unit 3, Keephills Unit 3, a portion of Poplar Creek and Castle River, four hydro facilities, and 11 additional wind farms 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.

McBride Lake, three hydro facilities, and a significant portion of Poplar Creek and Castle River 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.

For the year ended Dec. 31, 2011, production decreased 3,724 GWh compared to 2010, primarily due to the shut down at Sundance Units 1 and 2, the sale of the Meridian facility, and the decommissioning of Wabamun, partially offset by the commencement of commercial operations of Keephills Unit 3, lower planned and unplanned outages at the Alberta coal PPA facilities, higher wind volumes, and higher hydro volumes.

Comparable gross margin for the year ended Dec. 31, 2011 increased $18 million ($0.04 per installed MWh) compared to 2010 primarily due to higher hydro margins and the commencement of commercial operations at Keephills Unit 3, partially offset by the discontinuation of managing the base plant at Poplar Creek. The lower recoveries at the Poplar Creek base plant were offset by lower OM&A costs.

Eastern Canada

Our Eastern Canada assets consist of four natural gas-fired facilities, five hydro facilities, and four wind farms, with a total gross generating capacity of 1,411 MW (1,264 MW net ownership interest). All of our assets 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, 2011, production decreased 47 GWh compared to 2010 due to higher outages and unfavourable market conditions at natural gas-fired facilities, partially offset by higher wind volumes.

Gross margin for the year ended Dec. 31, 2011 increased $20 million ($0.16 per installed MWh) compared to 2010 primarily due to higher wind volumes at a higher price per installed MWh.

International

Our international assets consist of natural gas, coal, and hydro assets in various locations in the United States with a generating capacity of 1,589 MW and natural gas- and diesel-fired assets in Australia with a generating capacity of 300 MW.

Our Centralia Thermal, Centralia Gas, and Skookumchuck 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, 2011, production decreased 3,734 GWh compared to 2010, primarily due to higher planned and unplanned outages and higher economic dispatching at Centralia Thermal. The outages at Centralia did not negatively impact our gross margins for the year ended Dec. 31, 2011 as we were able to extend our planned outages to take advantage of lower market prices to purchase power on the market to fulfill our power contracts.

For the year ended Dec. 31, 2011, comparable gross margin increased $10 million ($0.06 per installed MWh) compared to 2010 primarily due to favourable pricing primarily driven by lower purchased power prices.

During 2011, unrealized pre-tax gains of $127 million were recorded in earnings due to certain hedges being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions are expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will do so during 2012. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

Operations, Maintenance, and Administration Expense

For the year ended Dec. 31, 2011, OM&A costs decreased compared to 2010 due to lower costs associated with the discontinuation of managing the base plant at Poplar Creek, partially offset by the writeoff of certain wind development costs, costs associated with several productivity initiatives, and the commencement of commercial operations of Keephills Unit 3.

Planned Maintenance

The table below shows the amount of planned maintenance capitalized and expensed:

Year ended Dec. 31	2011	2010
Capitalized	**184**	194
Expensed	**2**	3
	186	197
GWh lost	**2,872**	2,739

For the year ended Dec. 31, 2011, total planned maintenance costs decreased $11 million compared to 2010 due to fewer major coal outages due to the shut down of Sundance Units 1 and 2, partially offset by higher gas plant outages. In 2011, production lost as a result of planned maintenance increased 133 GWh compared to 2010 primarily due to higher planned outages at natural gas-fired facilities.

Depreciation Expense

For the year ended Dec. 31, 2011, depreciation expense increased compared to 2010 due to an increased asset base, the impact of the 2010 decrease in Wabamun decommissioning and restoration costs, and the writedown of capital spares, partially offset by changes to estimated residual values, the sale of the Meridian facility, and favourable foreign exchange rates.

Asset Impairment Charges

During 2011, we recorded a pre-tax impairment charge of $17 million related to four Generation assets within the renewables fleet that were part of the acquisition of Canadian Hydro, in order to write the assets down to their estimated fair values less cost to sell. The fair value estimates are derived from the long-range forecasts for the assets and prices evidenced in the marketplace. Two of the assets were impaired due to operational factors that impacted their useful lives, resulting in an impairment charge of $5 million. The impairment charges on the other two assets, totalling $12 million, resulted from our annual comprehensive impairment assessment and reflect lower forecast pricing at these merchant facilities.

During 2010, we recorded a pre-tax impairment charge of $28 million ($21 million after deducting the amount that was attributed to the non-controlling interest) on certain Generation assets, consisting of a $7 million charge against the natural gas fleet and a $21 million charge against the coal fleet. The natural gas fleet impairment reflects the pending sale of our 50 per cent interest in the Meridian facility, which was attributed to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and resulted from the shut down due to the physical state of the boilers such that the units cannot be economically restored to service under the terms of the PPA.

Finance Lease

Although we continue to operate the Fort Saskatchewan facility, our long-term contract was determined to be a finance lease under IFRS, as the principal risks and rewards of ownership have been transferred to the customer. As a result, the assets subject to the lease have been removed from PP&E and the amounts due under the lease have been recorded in the Consolidated Statements of Financial Position as a finance lease receivable. Under Canadian GAAP, we had proportionately consolidated our interest in the financial and operational results of the Fort Saskatchewan facility.

Fort Saskatchewan is a natural gas-fired facility with a gross generating capacity of 118 MW in operation, of which TA Cogen has a 60 per cent ownership interest (35 MW net ownership interest). Key operational information related to our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

Year ended Dec. 31	2011	2010
Availability *(%)*	**98.1**	97.1
Production *(GWh)*	**481**	488

Availability for the year ended Dec. 31, 2011 was comparable to 2010.

For the year ended Dec. 31, 2011, production decreased by 7 GWh compared to 2010 primarily due to lower customer demand partially offset by lower planned outages.

Finance lease income for the year ended Dec. 31, 2011 was consistent with 2010 at $8 million.

Equity Investments

Under IFRS, interests in joint ventures that are jointly controlled entities, like our CE Gen and Wailuku joint ventures, can be recognized using either the proportionate consolidation or equity method. We adopted the equity method to account for these interests to align with the requirements of IFRS 11 *Joint Arrangements* ("IFRS 11"), which was issued by the International Accounting Standards Board in May 2011. Under Canadian GAAP, we had proportionately consolidated our interests in the financial and operational results of CE Gen and Wailuku.

This change resulted in the reclassification of our share of assets and liabilities from each respective line item on our Consolidated Statements of Financial Position to a single line item entitled "Investments". Our proportionate share of revenue and expenses was also reclassified from each respective line item and presented as a single amount entitled "Equity income" on the Consolidated Statements of Earnings.

Our investments accounted for under the equity method are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 839 MW of gross generating capacity (390 MW net ownership interest). The table below summarizes key operational information from our investments accounted for under the equity method:

Year ended Dec. 31	2011	2010
Availability *(%)*	**94.9**	95.5
Production *(GWh)*		
Gas	**308**	411
Renewables	**1,312**	1,299
Total production	**1,620**	1,710

Availability for the year ended Dec. 31, 2011 decreased compared to 2010 due to higher planned and unplanned outages at our CE Gen facilities.

Production for the year ended Dec. 31, 2011 decreased compared to 2010 due to unfavourable market conditions and higher planned and unplanned outages.

Equity earnings from CE Gen and Wailuku for the year ended Dec. 31, 2011 were $14 million as compared to income of $7 million for 2010. The equity earnings increased primarily due to favourable market conditions, partially offset by unfavourable foreign exchange rates and higher planned and unplanned outages.

ENERGY TRADING: 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 Energy Trading's activities. Refer to the Value at Risk and Trading Positions discussion in the Risk Management section of this MD&A for further discussion on VaR.

Energy Trading manages available generating capacity, as well as the fuel and transmission needs, of the Generation Segment by utilizing contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results 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 IFRS. 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 Energy Trading is allocated to the Generation Segment based on an estimate of operating expenses and a percentage of resources dedicated to providing support and analysis. This fixed fee intersegment allocation is represented as a cost recovery in Energy Trading and an operating expense within Generation.

The results of the Energy Trading Segment, with all trading results presented on a net basis, are as follows:

Year ended Dec. 31	2011	2010
Revenues	**137**	41
Fuel and purchased power	**-**	-
Gross margin	**137**	41
Operations, maintenance, and administration	**43**	17
Depreciation and amortization	**1**	2
Intersegment cost allocation	**(8)**	(5)
Operating expenses	**36**	14
Operating income	**101**	27

For the year ended Dec. 31, 2011, Energy Trading gross margins increased compared to 2010 primarily due to strong trading results in the Western regions and increased earnings from the acquisition of electricity and natural gas contracts. These positive results were partially offset by lower gross margins in the Pacific Northwest region resulting from weak pricing.

For the year ended Dec. 31, 2011, OM&A costs increased compared to 2010 as a result of higher compensation costs associated with favourable results and costs associated with several productivity initiatives.

CORPORATE: Our Generation and Energy Trading 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.

The expenses incurred by the Corporate Segment are as follows:

Year ended Dec. 31	2011	2010
Operations, maintenance, and administration	**83**	69
Depreciation and amortization	**21**	19
Operating expenses	**104**	88

OM&A costs increased for the year ended Dec. 31, 2011 compared to 2010 due to costs associated with several productivity initiatives and higher compensation costs.

Net Interest Expense

Under IFRS, where discounting is used, the increase in the carrying amount of a provision, such as for decommissioning and restoration activities, associated with the passage of time is recognized as a finance cost and included in net interest expense. Under Canadian GAAP, this was recognized as part of depreciation and amortization expense or fuel and purchased power.

The components of net interest expense are shown below:

Year ended Dec. 31	2011	2010
Interest on debt	**228**	226
Interest income	**-**	(18)
Capitalized interest	**(31)**	(48)
Ineffectiveness on fair value hedges	**(1)**	-
Interest expense	**196**	160
Accretion of provisions	**19**	18
Net interest expense	**215**	178

Net interest expense for the year ended Dec. 31, 2011 increased compared to 2010 due to lower capitalized interest, lower interest income related to the resolution of certain tax matters in 2010, and higher interest rates, partially offset by favourable foreign exchange rates and lower debt levels.

Non-Controlling Interests

We own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural gas-fired and one coal-fired generating facility with a total gross generating capacity of 704 MW. Stanley Power owns the minority interest in TA Cogen. Natural Forces owns a 17 per cent interest in our Kent Hills facility, which operates 150 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.

Non-controlling interests on the Consolidated Statements of Earnings and Consolidated Statements of Financial Position relate to the earnings and net assets attributable to TA Cogen and Kent Hills that we do not own. On the Consolidated Statements of Cash Flows, cash paid to the minority shareholders of TA Cogen and Kent Hills is shown in the financing section as distributions paid to subsidiaries' non-controlling interests.

The earnings attributable to non-controlling interests for the year ended Dec. 31, 2011 increased compared to 2010 due to higher earnings at TA Cogen.

Income Taxes

Our income tax rates and tax expense are based on the earnings generated in each jurisdiction in which we operate and any permanent differences between how pre-tax income is calculated for accounting and tax purposes. If there is a timing difference between when an expense or revenue item is recognized for accounting and tax purposes, these differences result in deferred income tax assets or liabilities and are measured using the income tax rate expected to be in effect when these temporary differences reverse. The impact of any changes in future income tax rates on deferred income tax assets or liabilities is recognized in earnings in the period the new rates are substantively enacted.

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

Year ended Dec. 31	2011	2010
Earnings before income taxes	**449**	304
Income attributable to non-controlling interests	**(38)**	(24)
Equity income	**(14)**	(7)
Impacts associated with certain de-designated and ineffective hedges	**(127)**	(43)
Asset impairment charges	**17**	28
Gain on sale of facilities and development projects	**(16)**	-
Reserve on collateral	**18**	-
Other non-comparable items	**10**	-
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**299**	258
Income tax expense	**106**	24
Income tax expense related to impacts associated with certain de-designated and ineffective hedges	**(46)**	(15)
Income tax recovery related to asset impairment charges	**4**	12
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	30
Income tax expense related to gain on sale of facilities and development projects	**(4)**	-
Income tax recovery related to reserve on collateral	**5**	-
Reclassification of Part VI. 1 tax	**(2)**	-
Income tax recovery related to other non-comparable items	**3**	-
Income tax expense excluding non-comparable items	**66**	51
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items (%)	**22**	20

For the year ended Dec. 31, 2011, income tax expense excluding non-comparable items increased compared to 2010 due to higher comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

For the year ended Dec. 31, 2011, the effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items increased compared to 2010 due to the effect of certain deductions that do not fluctuate with earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

Financial Position

The following chart outlines significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2010 to Dec. 31, 2011:

	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	14	Increase in net earnings
Accounts receivable	129	Timing of customer receipts and higher revenues
Collateral paid	18	Increased collateral requirements associated with changes in forward prices
Income taxes receivable	(16)	Resolution of certain tax matters
Inventory	32	Lower production at our coal facilities and higher average coal costs
Assets held for sale	(60)	Completion of sale of the Meridian facility
Long-term receivable	18	Collateral on hand at MF Global Inc., net of reserve recognized
Risk management assets (current and long-term)	17	Price movements and changes in underlying positions
Other assets	(12)	Transfer of project to property, plant, and equipment and writeoff of development costs
Accounts payable and accrued liabilities	(19)	Timing of payments and lower capital accruals
Collateral received	(110)	Reduction in collateral received from counterparties associated with changes in forward prices
Income tax payable	14	Increase in net earnings
Dividends payable	(63)	Timing of common share dividend declarations
Long-term debt (including current portion)	(23)	Repayment of medium term note, offset by unfavourable foreign exchange movements and increased borrowings under credit facilities
Decommissioning and other provisions (current and long-term)	72	Increase in decommissioning and commercial provisions
Deferred credits and other long-term liabilities	36	Increase in defined benefit accrual
Deferred income tax liabilities	(47)	Increase in tax loss carry-forward balances
Risk management liabilities (current and long-term)	192	Price movements and changes in underlying positions
Equity attributable to shareholders	149	Increase in net earnings and issuance of preferred and common shares, offset by movements in accumulated other comprehensive (loss) income
Non-controlling interests	(73)	Distributions paid, partially offset by non-controlling interests' portion of net earnings

Financial Instruments

Financial instruments are used to manage our exposure to interest rates, commodity prices, currency fluctuations, as well as 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 generally not affect earnings until the financial instrument is settled.

We have two types of financial instruments: (1) those that are used in the Energy Trading 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 foreign operations.

A portion of our financial instruments and physical commodity contracts are recorded under own use accounting or qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge, and is outlined in further detail below.

For all types of hedges, 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. All financial instruments are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion is recognized in net earnings.

As well, there are certain contracts in our portfolio that at their inception do not qualify for, or we have chosen not to elect to apply, 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.

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

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 changes in the fair value of fixed rate long-term debt caused by variations in market interest rates. We use interest rate swaps in our fair value hedges.

All gains or losses related to interest rate swaps used in fair value hedges are recorded on the Consolidated Statements of Earnings. These gains or losses are, in turn, offset by the gains or losses related to the change in fair value of the debt due to the hedged risk. Any resulting net gain or loss is related to ineffectiveness in the fair value hedge relationship.

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 Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract [1]	–	–	–	–
Reporting date (marked-to-market)	✓	–	✓	–
Settle contract	✓	–	✓	✓

1 Some contracts may require an upfront cash investment.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate or commodity hedges and are used to offset foreign exchange, interest rate, and commodity price exposures resulting from market fluctuations.

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 Other Comprehensive Income ("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 Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract [2]	–	–	–	–
Reporting date (marked-to-market) [3]	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓

2 Some contracts may require an upfront cash investment.
3 Any ineffective portion is recorded in the Consolidated Statements of Earnings.

Foreign Exchange, Interest Rate, and Commodity Hedges

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps are used to offset the exposures resulting from foreign denominated long-term debt. Forward start interest rate swaps are used to offset the variability in cash flows resulting from anticipated issuances of long-term debt. When these instruments 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. The amounts previously recognized in OCI are reclassified to net earnings upon settlement of the financial instruments, or periodically, when the hedged forecast cash flows affect net earnings.

A summary of how typical foreign exchange, interest rate, and commodity hedges are recorded in our financial statements is as follows:

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

1 *Some 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 used in cash flow hedges to a net liability is primarily a result of changes in future prices on contracts in our Generation Segment and the impact of discontinued hedge accounting for certain contracts.

The fair value of the majority of our project, foreign exchange, interest rate, and commodity hedges are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. 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 IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore 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 reasonable possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2011, Level III instruments had a net liability carrying value of $14 million. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2010.

When we do not elect hedge accounting, or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest or exchange rates related to these financial instruments are recorded through the Consolidated Statements of Earnings in the period in which they arise.

Net Investment Hedges

Foreign currency forward contracts and foreign denominated long-term debt are used to hedge exposure to changes in the carrying values of our net investments in foreign operations having a functional currency other than the Canadian dollar. We attempt to manage our foreign exchange exposure by matching foreign denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our U.S. dollar debt.

Foreign exchange gains or losses related to net investment hedges are recorded in OCI until there is a permanent reduction in the net investment of the foreign operation. If there is a permanent reduction in the net investment of the foreign operation, the foreign exchange 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 Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[1]	–	–	–	–
Reporting date (marked-to-market)	–	✓	✓	–
Roll-over into new contract	–	✓	✓	✓
Settle contract	–	✓	✓	✓
Reduction of net investment of foreign operation	✓	✓	✓	–

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

Non-Hedges

Financial instruments not designated as hedges are used to reduce commodity price, foreign exchange, and interest rate risks. All gains or losses related to non-hedges are recorded in the Consolidated Statements of Earnings as they either do not qualify for, or have not been designated for, hedge accounting.

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 Statements of Financial Position	Consolidated Statements of Cash Flows
Enter into contract[2]	–	–	✓	–
Reporting date (marked-to-market)	✓	–	✓	–
Roll-over into new contract	✓	–	✓	✓
Settle contract	✓	–	✓	✓
Divest contract	✓	–	✓	✓

2 *Some contracts may require an upfront cash investment.*

Employee Share Ownership

We employ a variety of stock-based compensation plans to align employee and corporate objectives.

Under the terms of our Stock Option Plans, employees below manager level receive grants that vest in equal instalments over four years and expire after 10 years.

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, including the value of reinvested dividends over the period, 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 awarded, 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 for employees below vice-president level, and for two additional years for employees at the vice-president level and above. The effect of the PSOP does not materially affect the calculation of the total weighted average number of common shares outstanding.

Under the terms of the Employee Share Purchase Plan, we extend an interest-free loan to our employees below executive level for up to 30 per cent of the employee's base salary for the purchase of our common shares from the open market. The loan is repaid over a three-year period by the employee through payroll deductions unless the shares are sold, at which point the loan becomes due on demand. At Dec. 31, 2011, accounts receivable from employees under the plan totalled $1 million (2010 – $2 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, and in Canada there is an additional 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 for accounting purposes of the registered and supplemental pension plans were as at Dec. 31, 2011.

We provide other health and dental benefits to the age of 65 for both disabled members and retired members (other post-employment benefits). The last actuarial valuation of these plans was conducted at Dec. 31, 2011.

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 $63 million to secure the obligations under the supplemental plan.

Statements of Cash Flows

Our transition to IFRS changed the presentation of several items on the Consolidated Statements of Cash Flows. The most significant of these items is the effect of using the equity method instead of the proportionate consolidation method to account for our interests in CE Gen and Wailuku. Our share of CE Gen's and Wailuku's cash and cash equivalents and cash flow changes are no longer presented within each line item of the operating, investing, or financing activities sections of the Consolidated Statements of Cash Flows, and instead, cash distributions received are presented as an operating activity and cash returns of invested capital or additional cash invested are presented as an investing activity. The capitalization of costs associated with planned major maintenance and inspection activities that were previously expensed under Canadian GAAP will result in these cash expenditures being reported as an investing activity under IFRS. Under Canadian GAAP these expenditures impacted cash flow from operations.

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2011:

Year ended Dec. 31	2011	2010	Explanation of change
Cash and cash equivalents, beginning of year	**35**	53	
Provided by (used in):			
Operating activities	**694**	838	Unfavourable changes in working capital balances of $148 million primarily due to the timing of payments and receipts offset by higher cash earnings of $4 million
Investing activities	**(615)**	(765)	Decrease in additions to PP&E of $355 million and proceeds on the sale of facilities and development projects of $40 million, offset by a $156 million decrease in collateral received from counterparties, an increase of $54 million in collateral paid to counterparties, a decrease of $15 million in proceeds on the sale of the minority interest in Kent Hills, and a decrease of $26 million due to the resolution of certain tax matters in 2010
Financing activities	**(67)**	(90)	Lower net debt repayments, decrease in cash dividends paid on common shares of $25 million, offset by a decrease in proceeds on issuance of preferred shares of $24 million and an increase in dividends paid on preferred shares of $15 million
Translation of foreign currency cash	**2**	(1)	
Cash and cash equivalents, end of year	**49**	35	

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 or equity 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

Long-term debt totalled $4.0 billion at Dec. 31, 2011 compared to $4.1 billion at Dec. 31, 2010. Total long-term debt decreased from Dec. 31, 2010 primarily due to the maturity of a medium term note.

Credit Facilities

At Dec. 31, 2011, we had a total of $2.0 billion (2010 – $2.0 billion) of committed credit facilities of which $0.9 billion (2010 – $1.1 billion) is not drawn and is available, subject to customary borrowing conditions. At Dec. 31, 2011, the $1.1 billion (2010 – $0.9 billion) of credit utilized under these facilities was comprised of actual drawings of $0.8 billion (2010 – $0.6 billion) and of letters of credit of $0.3 billion (2010 – $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, that matures in 2015, with the remainder comprised of bilateral credit facilities that mature between the third and fourth quarter of 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

In addition to the $0.9 billion available under the credit facilities, we also have $49 million of cash.

Share Capital

At Dec. 31, 2011, we had 223.6 million (2010 – 220.3 million) common shares issued and outstanding. During the year ended Dec. 31, 2011, 3.3 million (2010 – 1.9 million) common shares were issued for $69 million (2010 – $40 million), of which $67 million (2010 – $35 million) was issued under the terms of the DRASP plan.

At Dec. 31, 2011, we had 23.0 million (2010 – 12.0 million) preferred shares issued and outstanding. During the year ended Dec. 31, 2011, 11.0 million (2010 - 12.0 million) Series C Preferred Shares were issued for $269 million, net of after-tax issuance costs of $6 million (2010 - $293 million, net of after-tax issuance costs of $7 million).

On March 1, 2012, we had 224.7 million common shares and 12.0 million Series A and 11.0 million Series C first preferred shares outstanding.

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, energy trading activities, hedging activities, and purchase obligations. At Dec. 31, 2011, we provided letters of credit totalling $328 million (2010 – $297 million) and cash collateral of $45 million (2010 – $27 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Working Capital

At Dec. 31, 2011, the excess of current liabilities over current assets is $67 million (2010 – $190 million). The excess of current liabilities over current assets decreased $123 million compared to 2010 due to an increase in accounts receivable, an increase in net risk management assets, favourable inventory movements, and a decrease in net collateral paid by counterparties, partially offset by an increase in net risk management liabilities and an increase in the current portion of long-term debt.

Capital Structure

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

As at Dec. 31	2011		2010	
	Amount	**%**	Amount	%
Debt, net of cash and cash equivalents	**3,988**	**52**	4,025	53
Non-controlling interests	**358**	**5**	431	6
Equity attributable to shareholders	**3,269**	**43**	3,120	41
Total capital	**7,615**	**100**	7,576	100

Commitments

Contractual repayments of 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 and transportation 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
2012	78	6	16	54	18	316	205	220	913
2013	45	8	11	54	17	622	191	-	948
2014	43	8	11	54	17	209	164	-	506
2015	22	8	11	54	17	1,167	125	-	1,404
2016	20	8	10	59	9	29	111	-	246
2017 and thereafter	484	5	42	291	3	1,680	843	-	3,348
Total	**692**	**43**	**101**	**566**	**81**	**4,023**	**1,639**	**220**	**7,365**

1 Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature between the fourth quarter of 2012 and the third quarter of 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.

As part of the Bill and MoA signed into law in the State of Washington, we have committed to fund $55 million over the life of the Centralia coal plant to support economic development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. In the event that legislation changes, this payment will no longer be required.

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or 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 unconsolidated structured entities or arrangements.

Climate Change and the Environment

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind, hydro, and geothermal, we also believe that coal and natural gas as fuels will continue to play an important role in meeting future energy needs. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low cost electricity.

Ongoing and Recently Passed Environmental Legislation

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business.

Alberta

In Alberta there are requirements for coal-fired generation units to implement additional air emission controls for NOx, sulphur dioxide ("SO_2"), and particulate matter once they reach the end of their PPAs, in most cases at 2020. These regulatory requirements were developed by the Province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance ("CASA"). However, as new GHG regulations for coal-fired power are developed there is a risk that the CASA air pollutant requirements and schedules become misaligned with GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with both the federal and provincial governments to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most economically effective manner while maintaining the reliability of Alberta's generation supply.

Canada

On Aug. 27, 2011, the Government of Canada published in the Canada Gazette draft regulations entitled "Reduction of CO_2 Emissions from Coal-Fired Generation of Electricity". These regulations propose a 45-year end-of-life for coal-fired power units, at which point the units would have to meet a GHG emissions performance standard similar to natural gas-fired levels, or close. Should they be passed, the regulations would become effective on July 1, 2015. Under federal consultation provisions, industry, provinces, and other stakeholders have 60 days to provide comments on the regulations and subsequently the federal government will consider this input in the development of the second draft.

We are currently in discussions with both the governments of Canada and Alberta about modifications to the regulations that would result in significant GHG emission reductions in the most economically efficient manner, and would also provide alignment with other current and future regulations on air pollutants and on natural gas generation. These discussions are expected to continue through early 2012.

United States

In the U.S., the Environmental Protection Agency ("EPA") announced on Sept. 14, 2011, that it was further delaying the release of draft GHG regulations for new and modified coal-fired power plants beyond its Sept. 30, 2011 target date. Draft regulations are now expected at the end of January 2012. There are no announced plans for new GHG regulations for existing power plants such as our Centralia plant.

In December 2011, the EPA issued national standards for mercury pollution from power plants. Existing sources will have up to four years to comply. We are already proceeding with the installation of voluntary mercury capture technology at the Centralia coal-fired plant, to be operational by the end of 2012. That plant is also planning for the installation of additional capture technology to further reduce oxides of nitrogen ("NOx"), consistent with the Washington State Bill passed in April 2011 requiring TransAlta to begin operating such technology by Jan. 1, 2013.

In addition to the Federal, Regional and State regulations that we must comply with, we also comply with the standards established by the North American Reliability Corporation ("NERC"). NERC is the electric reliability organization certified by the Federal Energy Regulatory Commission in the U.S. to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually; monitors the bulk-power system; and educates, trains and certifies industry personnel.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form and within the Risk Management section of this MD&A, many of our activities and properties are subject to environmental requirements, as well as changes in our liabilities under these requirements, which may have a material adverse effect upon our consolidated financial results.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We 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 Board of Directors provides oversight to our environmental management programs and emission reduction initiatives in order to ensure continued compliance with environmental regulations.

In 2011, we estimate that 36 million tonnes of GHGs with an intensity of 0.923 tonnes per MWh (2010 – 37 million tonnes of GHGs with an intensity of 0.976 tonnes per MWh) were emitted as a result of normal operating activities.[1]

Our environmental management programs encompass the following elements:

Renewable Power

We continue to invest in and build renewable power resources. Our Bone Creek hydro facility became operational in 2011 and our 68 MW New Richmond wind facility is currently under construction and slated for completion during the fourth quarter of 2012. A larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or through 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 have installed 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 Unit 3 plant began operation in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at Genesee Unit 3. Uprate projects at our Keephills and Sundance plants were undertaken in 2011 and scheduled for completion in 2012, which will improve the energy and emissions efficiency of those units.

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 discussions have allowed us to engage in proactive discussions with governments and industry participants to meet environmental requirements over the longer term.

1 *2011 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO_2, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.*

CCS Development

In October 2009, the governments of Canada and Alberta announced that Project Pioneer, our CCS project, had received funding commitments of more than $770 million. Since then, TransAlta has advanced engineering work on the capture, pipeline, and storage components of the project and is assessing if CCS costs and other commercial terms and risks are appropriate to ensure CCS is viable from a business perspective. If built, the prototype plant will be one of the largest integrated CCS power facilities in the world, designed to capture one megatonne of carbon dioxide ("CO_2") per year from the new 450 MW Keephills Unit 3 coal-fired plant. 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 offsets 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.

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, and 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 that 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 their attendant costs; expectations related to future earnings and cash flow from operating activities; estimates of fuel supply and demand conditions and the costs of procuring fuel; our estimated spend on growth and sustaining capital projects; 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; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; expectations for the outcome of existing or potential legal and contractual claims; expectations for the ability to access capital markets at reasonable terms; the impact of certain hedges on future reported earnings; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar; and the monitoring of our exposure to liquidity risk.

Factors that may adversely impact our forward looking statements include risks relating to: fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; the regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural disasters; the threat of domestic terrorism and cyber-attacks; equipment failure; energy trading risks; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal and contractual proceedings involving the Corporation; reliance on key personnel; labour relations matters; and development projects and acquisitions. Certain risk factors are described in further detail in the Risk Management section of this MD&A and under the heading "Risk Factors". The foregoing risk factors, among others, are described in further detail in our 2012 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 that projected results or events will be achieved.

2012 Outlook

Business Environment

Demand

Alberta electricity demand is expected to grow at an average rate of approximately three per cent annually over the next few years. Electricity demand in the Pacific Northwest is expected to increase approximately two per cent per year over the next three years due to expectations of a modest pace of economic recovery. However, the region's long-term growth rate is expected to be at the lower end of historical trends as there is a large emphasis on energy efficiency across the region. Demand in Ontario is expected to continue to grow at about one per cent annually.

Supply

New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy and natural gas-fired generation. This expectation is driven by the price reduction that has occurred in the North American natural gas market, combined with a continued expectation that GHG legislation of some form will be enacted in Canada and the U.S.

Alberta will likely see a decreasing reserve margin over the next several years until new supply is expected to come online around 2015. The Ontario reserve margin is expected to increase notably in 2012 through 2014 as nuclear capacity is refurbished and other new capacity comes online. The Pacific Northwest is also expected to see decreasing reserve margins in the near term, although the market is expected to remain well supplied.

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. Wind generation is also growing in Alberta, as 119 MW are currently under construction and over 1,200 MW, has received regulatory approval, although not all announced generation is expected to be built prior to transmission expansions are in place.

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

Transmission

Historically, transmission systems have been designed to serve loads in only their local area, and interties between jurisdictions that were built for reliability served only a small fraction of the local generation capacity or load. We believe future transmission lines will need to connect beyond provincial and state borders as there is a desire to improve efficiency by transmitting large quantities of electricity from one region to another. Such inter-regional lines will either be alternating current or direct current high voltage lines.

Power Prices

In 2012, power prices in Alberta are expected to be in line with 2011, driven by continued load growth, partially offset by lower natural gas prices. In the Pacific Northwest, we continue to expect weak prices due to low natural gas prices and slow load growth.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has indicated its intention to regulate GHG emissions from coal-fired power units by 2015. This regulatory framework is under discussion between the federal and provincial governments and the industry, and is expected to be finalized in 2012.

In the U.S., it is not yet clear how climate change legislation for existing fossil-fuel-based generation will unfold. Additionally, new air pollutant regulations for the power sector are anticipated in 2012, but will not directly affect our coal-fired operations in Washington State. TransAlta's agreement with Washington State, established in March 2011, provides regulatory clarity regarding an emissions regime related to the Centralia Coal plant until 2025.

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

The siting, construction, and operation of electrical energy facilities requires interaction with many stakeholders. More recently, certain stakeholders have brought actions against government agencies and owners over alleged adverse impacts of wind projects. We are monitoring these claims in order to assess the risk associated with these activities.

Economic Environment

The economic environment showed signs of improvement in 2011 and we expect this trend to continue through 2012 at a slow to moderate pace. We continue to monitor global events, including conditions in Europe, and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no counterparty losses in 2011, and 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.

We have recorded a provision on collateral held with MF Global Inc. Refer to the Significant Events section of this MD&A for further discusssion.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase for 2012 due to the completion of New Richmond and the three uprates at our Alberta PPA facilities. Prior to the effect of any economic dispatching, overall production is expected to increase for 2012 due to a full year of operating Keephills Unit 3 and lower unplanned outages, offset by higher than normal major maintenance or planned outages, scheduled in the thermal fleet in 2012. Overall availability is expected to be in the range of 89 to 90 per cent in 2012 due to lower unplanned outages.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average approximately 70 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis, we target being up to 90 per cent contracted for the upcoming year, stepping down to 65 per cent in the fourth year. As at the end of 2011, approximately 86 per cent of our 2012 capacity was contracted through the use of PPAs, long-term, and short-term contracts. The average price of our short-term physical and financial contracts for 2012 ranges from $60 to $65 per MWh in Alberta, and from U.S.$50 to U.S.$55 per MWh in the Pacific Northwest.

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 mine are minimized through the application of standard costing. Coal costs for 2012, on a standard cost basis, are expected to increase by approximately four per cent compared to 2011 due to the drivers mentioned above.

Although we own the Centralia mine in the State of Washington, it currently is not operational. Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2012 is expected to increase by approximately nine per cent due to higher diesel, commodity costs, and coal dust mitigation expenses.

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 could reduce the year to year volatility of prices in the near term.

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 for 2012 are expected to be approximately five per cent lower than 2011 OM&A.

Energy Trading

Earnings from our Energy Trading Segment are affected by prices in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2012 objective is for Energy Trading to contribute between $65 million and $85 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, Euro, and Australian dollar by offsetting foreign denominated assets with foreign denominated liabilities and by entering into foreign exchange contracts. We also have foreign denominated expenses, including interest charges, which largely offset our net foreign denominated revenues.

Net Interest Expense

Net interest expense for 2012 is expected to be higher than our reported 2011 net interest expense mainly due to lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative 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 in the future. To mitigate this liquidity risk, we expect to maintain $2.0 billion of committed credit facilities, and will continuously monitor our exposures and obligations.

Accounting Estimates

A number of our accounting estimates, including those outlined in 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 and asset valuation for our asset impairment calculations.

Income Taxes

The effective tax rate on earnings excluding non-comparable items for 2012 is expected to be approximately 20 to 25 per cent.

Capital Expenditures

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

Growth Capital Expenditures

In 2011, we spent a total of $123 million on growth capital expenditures, net of any joint venture contributions received. We successfully commenced commercial operations at Keephills Unit 3 and Bone Creek. In addition, of the $123 million, $50 million is associated with four significant growth projects that will be completed in 2012.

A summary of the significant projects that are in progress is outlined below:

	Total project		2011[1]	2012		
Project	Estimated spend	Spent to date[2]	Actual spend	Estimated spend	Target completion date	Details
Keephills Unit 1 uprate	25	13	9	10-20	Q3 2012	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	26	10	4	10-20	Q2 2012	A 23 MW efficiency uprate at our Keephills facility
Sundance Unit 3 uprate	27	11	8	15-20	Q4 2012	A 15 MW efficiency uprate at our Sundance facility
New Richmond[3]	205	29	29	165-185	Q4 2012	A 68 MW wind farm in Quebec
Total growth	**283**	**63**	**50**	**200-245**		

1 In 2011, we also spent a combined total of $73 million on Keephills Unit 3, Bone Creek, Ardenville, and Kent Hills 2. Keephills Unit 3 amounts spent included a non-capital expenditure of $7 million and a coal cost reduction of $2 million. Bone Creek amounts spent as of Dec. 31, 2011 included a non-capital credit of $9 million.
2 Represents amounts spent as of Dec. 31, 2011.
3 New Richmond amounts spent as of Dec. 31, 2011 include expenditures of $5 million, which had been previously included in project development costs.

Transmission

For the year ended Dec. 31, 2011, a total of $5 million was spent on transmission projects. The estimated spend for 2012 for transmission projects is $8 million. Transmission projects consist of the major maintenance and reconfiguration of the transmission networks of Alberta to increase capacity of power flow in the lines.

Sustaining Capital Expenditures

A significant portion of our sustaining capital expenditures is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Some of these amounts were previously expensed under Canadian GAAP. Under IFRS, planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event.

For 2012, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Spent in 2011	Expected spend in 2012
Routine capital	Expenditures to maintain our existing generating capacity	114	100 - 115
Productivity capital	Projects to improve power production efficiency	42	70 - 90
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	21	40 - 50
Planned maintenance	Regularly scheduled major maintenance	184	290 - 310
Total sustaining expenditures		**361**	**500 - 565**

Details of the 2012 planned maintenance program, including major inspection costs, are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2012
Capitalized	215 - 230	75 - 80	290 - 310
Expensed	0 - 0	0 - 5	0 - 5
	215 - 230	75 - 85	290 - 315

	Coal	Gas and Renewables	Total
GWh lost	2,880 - 2,890	420 - 430	3,300 - 3,320

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 financial position, and the amount of capital available to us under existing committed credit facilities.

Risk Management

Our business activities expose us to a 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.

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

The Board of Directors provides stewardship of the Corporation; ensures that the Corporation establishes policies and procedures for the identification, assessment and management of principal risks; 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 review consists 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 interrelated with each other, and identifies the applicable risk metrics.

The 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 and 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 and Financial Exposure Management policies and reviews quarterly ERM reporting.

The Risk Management Committee ("RMC") is chaired by our Chief Financial Officer and is comprised of the Executive Vice-President Corporate Development, Treasurer, Managing Director Trading, Executive Vice-President Operations, Vice-President Risk, and Chief Engineer. The RMC acts as the operational and financial risk oversight body for the Corporation.

The Technical Risk and Commercial Team ("TRACT") is a committee chaired by the Vice-President, Engineering, Environment, and Construction Services, 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.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster 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 sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exceptional approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a corporate code of conduct on an annual basis.

Reporting

On a regular basis, risk exposures are reported to key decision makers including the Board of Directors, senior management, and the RMC. Reporting to the RMC includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion of actions to minimize risks. 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 anonymously report any potential ethical concerns. These concerns can be submitted anonymously, either directly to the ARC or to the Director, 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 chair of the ARC.

Value at Risk and Trading Positions

VaR is the primary measure used to manage our exposure to market risk resulting from energy trading activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in energy trading positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2011 associated with our proprietary energy trading activities was $5 million (2010 - $5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. 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 of changes in certain key variables. The analysis is based on business conditions and production volumes in 2011. 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. For example, the financial performance of our hydro, wind, and geothermal operations are partially dependent upon the availability of their input resources in a given year. 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.

We manage volume risk 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 required,
- monitoring water resources throughout Alberta and British Columbia to the best of our ability and optimizing this resource against real-time electricity market opportunities, and
- 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.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	24

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal, and corrosion damage in boilers, generators, and turbines, 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 may be required to compensate the purchaser for the loss in the availability of production or record reduced energy 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 availability 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 coverage 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 lifecycles 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 the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short-, medium-, and long-term contracts to mitigate 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.

In 2011, we had approximately 93 per cent of production under short-term and long-term contracts and hedges (2010 – 95 per cent). In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfill our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the costs of fuels used in production 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.

In 2011, 69 per cent (2010 – 81 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2010 – 100 per cent) of our purchased coal costs were contractually fixed.

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

Factor	Increase or decrease	Approximate impact on net earnings
Electricity price	$1.00/MWh	6
Natural gas price	$0.10/GJ	1
Coal price	$1.00/tonne	12

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 our coal-fired plants, input costs, such as diesel, tires, the price of mining equipment, the volume of overburden removed to access coal reserves, and the location of mining operations relative to the power plants are some of the exposures in our mining operations. 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 coal 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, 2011, approximately 79 per cent (2010 – 75 per cent) of the coal used in generating activities is from coal reserves that we own,
- 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 existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the U.S. 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 management system in place that is designed to continuously improve environmental performance,
- committing significant effort to work with regulators in Canada and the U.S. 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, SO_2, 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 and hydro generation, and
- investing in clean coal technology development, which potentially provides long-term promise for large emission reductions from fossil fuel 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 2011, we spent approximately $47 million (2010 – $50 million) on environmental management activities, systems, and processes.

We are a founder of the Canadian Clean Power Coalition and the Integrated CO_2 Network, industry consortia dedicated to developing clean combustion technologies, which in turn will reduce the environmental and financial risks associated with continued fossil fuel use for power generation.

The Canadian Securities Administrators published guidance on environmental disclosure in Staff Notice 51-333. The guidance directs issuers to address:

- environmental risks and related matters,
- environmental risk oversight and management,
- forward looking information requirements as they relate to environmental goals and targets, and
- the impact of the adoption of IFRS on disclosure of environmental liabilities.

TransAlta has reviewed this guidance and believe that we comply with these requirements.

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 results from the ability of a counterparty to either fulfill its 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 the creditworthiness of counterparties, contract term limits, and the 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 its obligation or goes over its 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.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2010. We had no counterparty losses in 2011, and 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. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required although no assurance can be given that we will always be successful.

A summary of our credit exposure for our energy trading operations and hedging activities at Dec. 31, 2011 is provided below:

Counterparty credit rating	Net exposure amount
Investment grade	258
Non-investment grade	-
No external rating, internally rated as investment grade	70
No external rating, internally rated as non-investment grade	24

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 $38 million (2010 – $43 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, the acquisition of equipment and services and foreign denominated commodities from foreign suppliers, and our U.S. denominated debt. Our exposures are primarily to the U.S., Euro, 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 or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that include:

- 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 such foreign currency exposures. At Dec. 31, 2011, we have hedged approximately 92 per cent (2010 – 95 per cent) of our foreign currency net investment exposure,
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure, and
- entering into forward foreign exchange contracts to hedge future foreign denominated receipts and expenditures, and all U.S. denominated debt outside of our net investment portfolio.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that a six cent increase or decrease in the U.S., Euro or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.06	4

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used for energy 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 financial position 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 energy trading activities on a regular basis to the RMC, senior management, and Board of Directors,
- maintaining investment grade credit ratings, and
- maintaining sufficient undrawn 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 establishing and adhering to policies that include:

- 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, 2011, approximately 23 per cent (2010 – 25 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	8

Project Management Risk

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

We manage 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 senior management and Board of Directors 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 Unit 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,
- managing 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 2011, 44 per cent (2010 – 46 per cent) of our labour force was covered by 11 (2010 – 11) collective bargaining agreements. In 2011, three (2010 – four) agreements were renegotiated. We anticipate negotiating three agreements in 2012. 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 potential changes to the 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 of those transmission lines are key in our ability to deliver energy produced at our power plants to our customers. However, with the continued growth in demand for electricity coupled with very little transmission capacity being added and the reduced reliability and available capacity on the existing transmission facilities, the risks associated with the aging existing transmission infrastructure in Alberta, Ontario, and the Pacific Northwest continue 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.

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, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, 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 IFRS, 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	3

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2011 was 22 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 that 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. There can be no assurance that any particular claim will be resolved in our favour or that such claims may not have a material adverse effect on us.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 2011. 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 2 to the consolidated financial statements. The most critical of these policies are those related to revenue recognition, financial instruments and hedges, PP&E, project development costs, goodwill, income taxes, employee future benefits, and decommissioning and other provisions. 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.

These critical accounting estimates are described as follows:

Revenue Recognition

The majority of our revenues are derived from the sale of physical power, leasing of power facilities, and from energy trading activities.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, 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, at market prices, for each MWh produced and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered a lease. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above.

Energy 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 financial position date represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position 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. Some of our derivatives 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 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 we have access. In the absence of an active market, we determine 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, we look primarily to external readily observable market inputs. In limited circumstances, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy we use are defined below:

Level I

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

Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis and location differentials. We include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also 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, we use 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, we rely 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, we 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 for individual non-standard deals and structured products, 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.

We also have various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

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

The effect of using reasonable possible alternative assumptions as inputs to valuation techniques from which the Level III fair values are determined at Dec. 31, 2011 is estimated to be +/- $33 million (2010 – +/- $14 million). Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

Valuation of PP&E and Associated Contracts

As at Dec. 31, 2011, PP&E makes up 75 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, or the cash generating unit ("CGU") to which it belongs, is in excess of its recoverable amount.

Factors that could indicate that an impairment exists include significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in our overall business strategy; or 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 market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the PP&E or CGU to which it belongs. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. In estimating either fair value less costs to sell or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management uses 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. These estimates and assumptions are susceptible to change from period to period and 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.

As a result of our review in 2011, pre-tax asset impairment charges of $17 million were recorded related to certain renewables facilities. Refer to the Asset Impairment Charges section of this MD&A for further details.

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 recognized 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 us, at which time the costs incurred subsequently are included in PP&E or Investments. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and unrecoverable amounts of capitalized costs for projects no longer probable of occurring are charged to net earnings.

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. 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. 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, the potential for technological obsolescence, and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2011, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $532 million (2010 – $511 million), of which $40 million (2010 – $37 million) relates to mining equipment, and is included in fuel and purchased power.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently, if indicators of impairment exist. If the carrying amount of a CGU, including goodwill, exceeds the unit's fair value, any excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

Goodwill arose on the acquisitions of Canadian Hydro, Merchant Energy Group of the Americas, Inc., and Vision Quest Windelectric Inc. At Dec. 31, 2011, this goodwill had a total carrying amount of $447 million (2010 – $447 million). Under the equity method of accounting, the goodwill arising on the acquisition of CE Gen is included in the determination of the amount of the investment in CE Gen and is tested for impairment as part of the net investment.

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

Determining the fair value of the CGUs 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 CGUs declining by 10 per cent from current levels, there would not have been any impairment of goodwill.

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred assets and liabilities. 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 IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Deferred income tax assets of $176 million have been recorded on the Consolidated Statements of Financial Position at Dec. 31, 2011 (2010 – $178 million). These assets primarily relate to net operating and capital loss carryforwards. We believe there will be sufficient taxable income and capital gains that will permit the use of these carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $491 million have been recorded on the Consolidated Statements of Financial Position at Dec. 31, 2011 (2010 – $538 million). These liabilities are comprised primarily of taxes on unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Employee Future Benefits

We provide selected pension and post-employment 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 to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

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, 2011, the plan assets had a positive return of $11 million, compared to $28 million in 2010. The 2011 actuarial valuation used the same rate of return on plan assets (seven per cent) as was used in 2010.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for PP&E in the period in which they are incurred if there is a legal or constructive obligation 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 decommissioning and restoration provisions. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

At Dec. 31, 2011, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $275 million (2010 – $247 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.0 billion, which will be incurred between 2012 and 2072. The majority of these costs will be incurred between 2020 and 2050. The average discount used to calculate the carrying value of the decommissioning and restoration provisions was six per cent.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	3
Undiscounted decommissioning and restoration provision	1	–

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms and force majeure claims. These provisions, and subsequent changes thereto, are determined using our best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

Future Accounting Changes

Consolidated Financial Statements

In May 2011, the International Accounting Standards Board ("IASB") issued IFRS 10 *Consolidated Financial Statements*, which replaces International Accounting Standard 27 *Consolidated and Separate Financial Statements* ("IAS 27") and Standing Interpretations Committee Interpretation 12 *Consolidation – Special Purpose Entities* ("SIC-12"). IFRS 10 provides a revised definition of control so that a single control model can be applied to all entities for consolidation purposes.

Joint Arrangements

In May 2011, the IASB issued IFRS 11, which supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principle-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its joint arrangements. IFRS 11 also generally requires the use of the equity method of accounting for interests in joint ventures. Improvements in disclosure requirements are intended to allow investors to gain a better understanding of the nature, extent and financial effects of the activities that an entity carries out through joint arrangements.

Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in consolidated and unconsolidated entities, such as subsidiaries, joint arrangements, associates, and unconsolidated structured entities (special purpose entities).

Investments in Associates and Joint Ventures and Separate Financial Statements

In May 2011, two existing standards, IAS 28 *Investments in Associates and Joint Ventures* and IAS 27 *Separate Financial Statements*, were amended. The amendments are not significant, and result from the issuance of IFRS 10, IFRS 11, and IFRS 12.

The requirements of the preceding new standards and amendments to existing standards outlined above are effective for annual periods beginning on or after Jan. 1, 2013. The disclosure requirements of IFRS 12 may be incorporated into the financial statements earlier than Jan. 1, 2013. However, early adoption of the other standards is only permitted if all five are applied at the same time. We are currently assessing the impact of adopting these new standards and amendments on the consolidated financial statements, and do not expect the impact to be significant.

Fair Value Measurements

In June 2011, the IASB issued IFRS 13 *Fair Value Measurements*, which establishes a single source of guidance for all fair value measurements required by other IFRS; clarifies the definition of fair value; and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability or its own equity instrument at fair value. IFRS 13 is effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. We are currently assessing the impact of adopting IFRS 13 on the consolidated financial statements.

Presentation of Financial Statements

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The amendments to IAS 1 are effective for annual periods beginning on or after July 1, 2012. Earlier application is permitted. As a result of the amendment, the items presented within the Statement of Other Comprehensive Income will be reorganized to comply with the required groupings.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits* to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service cost is presented in net earnings; finance cost is presented as part of finance costs in net earnings; and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI. The amendments eliminate the option to defer the recognition of actuarial gains and losses, known as the 'corridor method'. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. We are currently assessing the impact of adopting the amendments to IAS 19 on the consolidated financial statements.

Financial Instruments

In November 2009, the IASB issued IFRS 9 *Financial Instruments,* which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or fair value through profit or loss or through OCI depending on the basis of the entity's business model for managing the financial asset, and the contractual cash flow characteristics of the financial asset.

In October 2010, the IASB issued additions to IFRS 9 regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

In December 2011, the IASB amended the effective date of these requirements, which are now effective for annual periods beginning on or after Jan. 1, 2015, and must be applied on a modified retrospective basis. Earlier adoption is permitted. The December amendment also provided relief from restating comparative periods and from the associated disclosures required under IFRS 7 *Financial Instruments: Disclosures.* We are currently assessing the impact of adopting these amendments on the consolidated financial statements.

Stripping Costs in the Production Phase of a Surface Mine

In October 2011, the International Financial Reporting Standards Interpretations Committee issued Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine* ("IFRIC 20"), which clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods. The Interpretation is effective for annual periods beginning on or after Jan. 1, 2013, with earlier application permitted. We are currently assessing the impact of adopting IFRIC 20 on the consolidated financial statements.

Offsetting Financial Assets and Liabilities

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation*. The amendments are intended to clarify certain aspects of the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements on offsetting. The IASB also amended IFRS 7 to require information about all recognized financial instruments that are set off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set off under IAS 32.

The amendments to IAS 32 are effective for annual periods beginning on or after Jan. 1, 2014. However, the new offsetting disclosure requirements are effective for annual periods beginning on or after Jan. 1, 2013 and interim periods within those annual periods. The amendments need to be provided retrospectively to all comparative periods. We are currently assessing the impact of adopting these amendments on the consolidated financial statements.

Non-IFRS Measures

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

Reconciliation to Net Earnings Attributable to Common Shareholders

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

Year ended Dec. 31	2011	2010
Revenues	**2,663**	2,673
Fuel and purchased power	**947**	1,185
Gross margin	**1,716**	1,488
Operations, maintenance, and administration	**545**	510
Depreciation and amortization	**482**	464
Taxes, other than income taxes	**27**	27
Operating expenses	**1,054**	1,001
Operating income	**662**	487
Finance lease income	**8**	8
Equity income	**14**	7
Gain on sale of assets	**16**	-
Other income	**2**	-
Foreign exchange (loss) gain	**(3)**	8
Asset impairment charges	**(17)**	(28)
Reserve on collateral	**(18)**	-
Net interest expense	**(215)**	(178)
Earnings before income taxes	**449**	304
Income tax expense	**106**	24
Net earnings	**343**	280
Non-controlling interests	**38**	24
Net earnings attributable to TransAlta shareholders	**305**	256
Preferred share dividends	**15**	1
Net earnings attributable to common shareholders	**290**	255

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 results from prior periods. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the year. In calculating comparable earnings, we exclude the impact related to certain hedges deemed ineffective for accounting purposes, as these transactions are unusual in nature and have not historically been a normal occurrence in the course of operating our business. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings in the period in which they settle. As these gains have already been recognized in earnings in the current period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

In calculating comparable earnings for 2011, we have also excluded the gain on the sale of facilities and development projects, the writeoff of acquired wind development costs, the writedown of certain capital spares, asset impairment charges, and reserve on collateral, as these items are not considered regular business activities.

In calculating comparable earnings for 2010, we also excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

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

Year ended Dec. 31	2011	2010
Net earnings attributable to common shareholders	**290**	255
Impacts associated with certain de-designated and ineffective hedges, net of tax	**(81)**	(28)
Gain on sale of facilities and development projects, net of tax	**(12)**	-
Writeoff of wind development costs, net of tax	**4**	-
Writedown of capital spares, net of tax	**3**	-
Asset impairment charges, net of tax	**13**	16
Reserve on collateral, net of tax	**13**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	(30)
Earnings on a comparable basis	**230**	213
Weighted average number of common shares outstanding in the year	**222**	219
Earnings on a comparable basis per share	**1.04**	0.97

Comparable EBITDA

Presenting comparable 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	2011	2010
Operating income	**662**	487
Depreciation and amortization per the Consolidated Statements of Cash Flows [1]	**532**	511
EBITDA	**1,194**	998
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(127)**	(43)
Writeoff of wind development costs, pre-tax	**6**	-
Writedown of capital spares, pre-tax	**4**	-
Comparable EBITDA	**1,077**	955

1 *To calculate comparable EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in fuel and purchased power on the Consolidated Statements of Earnings.*

Funds From Operations and Funds From Operations per Share

Presenting funds from operations and funds from operations per share from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Funds from operations per share is calculated using the weighted average number of common shares outstanding during the period.

Year ended Dec. 31	2011	2010
Cash flow from operating activities	**694**	838
Change in non-cash operating working capital balances	**115**	(33)
Funds from operations	**809**	805
Weighted average number of common shares outstanding in the year	**222**	219
Funds from operations per share	**3.64**	3.68

Free Cash Flow

Free cash flow represents the amount of cash generated by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments of debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash flow with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects.

Sustaining capital expenditures for the year ended Dec. 31, 2011, represents total additions to PP&E and intangibles per the Consolidated Statements of Cash Flows less $125 million ($123 million net of joint venture contributions) that we have invested in growth projects. In 2010, we invested $482 million ($470 million net of joint venture contributions).

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

Year ended Dec. 31	2011	2010
Cash flow from operating activities	**694**	838
Add (deduct):		
Changes in working capital	**115**	(33)
Sustaining capital expenditures	**(361)**	(355)
Dividends paid on common shares	**(191)**	(216)
Dividends paid on preferred shares	**(15)**	-
Distributions paid to subsidiaries' non-controlling interests	**(61)**	(62)
Free cash flow	**181**	172

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

Comparable Return on Capital Employed ("ROCE")

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 Accumulated Other Comprehensive (Loss) Income ("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 ROCE is presented below:

Year ended Dec. 31	2011	2010
Net earnings attributable to common shareholders before income taxes per the Consolidated Statements of Earnings	**449**	304
Net interest expense	**215**	178
Non-comparable items		
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(127)**	(43)
Gain on sale of facilities and development projects, pre-tax	**(16)**	-
Writeoff of wind development costs, pre-tax	**6**	-
Writedown of capital spares, pre-tax	**4**	-
Asset impairment charges, pre-tax	**17**	28
Reserve on collateral, pre-tax	**18**	-
Comparable earnings before net interest expense, non-controlling interests, and income taxes	**566**	467
Average invested capital excluding AOCI	**7,554**	7,357
Comparable ROCE	**7.5**	6.3

Selected Quarterly Information

	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Revenue	**818**	**515**	**629**	**701**
Net earnings attributable to common shareholders	**204**	**12**	**50**	**24**
Net earnings per share attributable to common shareholders, basic and diluted	**0.92**	**0.05**	**0.22**	**0.11**
Comparable earnings per share	**0.34**	**0.29**	**0.27**	**0.13**

	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Revenue	696	547	651	779
Net earnings attributable to common shareholders	60	63	40	92
Net earnings per share attributable to common shareholders, basic and diluted	0.27	0.29	0.18	0.42
Comparable earnings per share	0.27	0.15	0.18	0.36

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

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, 2011, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

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, TransAlta 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 responsibilities 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.

Dawn Farrell
President and Chief Executive Officer

Brett Gellner
Chief Financial Officer

March 1, 2012

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 Corporation.

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 proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint ventures and equity accounts for the CE Generation, LLC ("CE Gen") and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures in accordance with International Financial Reporting Standards ("IFRS"). 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 2011 consolidated financial statements of TransAlta Corporation included $927 million and $873 million of total and net assets, respectively, as of December 31, 2011, and $232 million and $108 million of revenues and net earnings, respectively, for the year then ended related to these joint ventures.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at December 31, 2011, 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 December 31, 2011, 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.

Dawn Farrell President and Chief Executive Officer	Brett Gellner Chief Financial Officer

March 1, 2012

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, 2011, 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 Gen, Sheerness, Wailuku, and Genesee Unit 3 joint ventures, which are included in the 2011 consolidated financial statements of the Corporation and constituted $927 million and $873 million of total and net assets, respectively, as of December 31, 2011, and $232 million and $108 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the CE Gen, Sheerness, Wailuku, and Genesee Unit 3 joint ventures.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 statements of financial position of TransAlta Corporation as at December 31, 2011 and 2010, and January 1, 2010, and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for the years ended December 31, 2011 and 2010, and our report dated March 1, 2012, expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada
March 1, 2012

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010, and January 1, 2010, and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for the years ended December 31, 2011 and 2010, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated 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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2011 and 2010, and January 1, 2010, and its financial performance and its cash flows for the years ended December 31, 2011 and 2010, in accordance with International Financial Reporting Standards.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as at December 31, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2012 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants

Calgary, Canada
March 1, 2012

Consolidated Statements of Earnings

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2011**	2010
Revenues	**2,663**	2,673
Fuel and purchased power *(Note 5)*	**947**	1,185
	1,716	1,488
Operations, maintenance, and administration *(Note 5)*	**545**	510
Depreciation and amortization	**482**	464
Taxes, other than income taxes	**27**	27
	1,054	1,001
	662	487
Finance lease income *(Note 6)*	**8**	8
Equity income *(Note 7)*	**14**	7
Gain on sale of assets *(Note 4)*	**16**	-
Other income	**2**	-
Foreign exchange (loss) gain	**(3)**	8
Asset impairment charges *(Note 8)*	**(17)**	(28)
Reserve on collateral *(Notes 14 and 16)*	**(18)**	-
Net interest expense *(Note 9 and 14)*	**(215)**	(178)
Earnings before income taxes	**449**	304
Income tax expense *(Note 10)*	**106**	24
Net earnings	**343**	280
Net earnings attributable to:		
TransAlta shareholders	**305**	256
Non-controlling interests *(Note 11)*	**38**	24
	343	280
Net earnings attributable to TransAlta shareholders	**305**	256
Preferred share dividends *(Note 25)*	**15**	1
Net earnings attributable to common shareholders	**290**	255
Weighted average number of common shares outstanding in the year *(millions)*	**222**	219
Net earnings per share attributable to common shareholders, basic and diluted *(Note 24)*	**1.31**	1.16

See accompanying notes.

Consolidated Statements of Comprehensive Income

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2011**	2010
Net earnings	**343**	280
Other comprehensive (loss) income		
Gains (losses) on translating net assets of foreign operations	**32**	(57)
(Losses) gains on financial instruments designated as hedges of foreign operations, net of tax [1]	**(33)**	33
Reclassification of gains on translation of foreign operations to net earnings, net of tax [2]	**-**	(3)
(Losses) gains on derivatives designated as cash flow hedges, net of tax [3]	**(103)**	147
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax [4]	**-**	8
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax [5]	**(177)**	(129)
Net actuarial losses on defined benefit plans, net of tax [6]	**(26)**	(20)
Other comprehensive loss	**(307)**	(21)
Comprehensive income	**36**	259
Total comprehensive income attributable to:		
Common shareholders	**18**	252
Non-controlling interests	**18**	7
	36	259

1 Net of income tax recovery of 5 for the year ended Dec. 31, 2011 (2010 – 6 expense).
2 Net of income tax of nil for the year ended Dec. 31, 2011 (2010 – nil).
3 Net of income tax recovery of 7 for the year ended Dec. 31, 2011 (2010 – 87 expense).
4 Net of income tax of nil for the year ended Dec. 31, 2011 (2010 – 3 recovery).
5 Net of income tax expense of 94 for the year ended Dec. 31, 2011 (2010 – 65 expense).
6 Net of income tax recovery of 9 for the year ended Dec. 31, 2011 (2010 – 7 recovery).

See accompanying notes.

Consolidated Statements of Financial Position

(in millions of Canadian dollars)	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Cash and cash equivalents *(Note 13)*	**49**	35	53
Accounts receivable *(Notes 12, 13, and 16)*	**541**	412	405
Current portion of finance lease receivable *(Notes 6 and 13)*	**3**	2	2
Collateral paid *(Notes 13 and 14)*	**45**	27	27
Prepaid expenses	**8**	10	18
Risk management assets *(Notes 13 and 14)*	**391**	268	146
Income taxes receivable	**2**	18	38
Inventory *(Note 15)*	**85**	53	90
Assets held for sale *(Note 4)*	**–**	60	4
	1,124	885	783
Investments *(Note 7)*	**193**	190	202
Long-term receivable *(Notes 13, 14 and 16)*	**18**	–	49
Finance lease receivable *(Notes 6 and 13)*	**42**	46	48
Property, plant, and equipment *(Notes 17 and 36)*			
Cost	**11,420**	11,040	10,831
Accumulated depreciation	**(4,132)**	(3,746)	(3,754)
	7,288	7,294	7,077
Goodwill *(Notes 18 and 36)*	**447**	447	447
Intangible assets *(Notes 19 and 36)*	**283**	288	293
Deferred income tax assets *(Note 10)*	**176**	178	229
Risk management assets *(Notes 13 and 14)*	**99**	205	222
Other assets *(Note 20 and 36)*	**90**	102	103
Total assets	**9,760**	9,635	9,453
Accounts payable and accrued liabilities *(Notes 13 and 14)*	**463**	482	484
Decommissioning and other provisions *(Note 21)*	**99**	54	61
Collateral received *(Notes 13 and 14)*	**16**	126	86
Risk management liabilities *(Notes 13 and 14)*	**208**	35	45
Income taxes payable	**22**	8	9
Dividends payable *(Notes 13, 14, 24 and 25)*	**67**	130	61
Current portion of long-term debt *(Notes 13, 14 and 22)*	**316**	237	9
Liabilities held for sale *(Note 4)*	**–**	3	–
	1,191	1,075	755
Long-term debt *(Notes 13, 14 and 22)*	**3,721**	3,823	4,231
Decommissioning and other provisions *(Note 21)*	**283**	256	287
Deferred income tax liabilities *(Note 10)*	**491**	538	542
Risk management liabilities *(Notes 13 and 14)*	**142**	123	78
Deferred credits and other long-term liabilities *(Note 23)*	**305**	269	236
Equity			
Common shares *(Note 24)*	**2,273**	2,204	2,164
Preferred shares *(Note 25)*	**562**	293	–
Contributed surplus	**9**	7	5
Retained earnings	**527**	431	495
Accumulated other comprehensive (loss) income *(Note 26)*	**(102)**	185	189
Equity attributable to shareholders	**3,269**	3,120	2,853
Non-controlling interests *(Note 11)*	**358**	431	471
Total equity	**3,627**	3,551	3,324
Total liabilities and equity	**9,760**	9,635	9,453

Contingencies *(Notes 32 and 35)*
Commitments *(Notes 14 and 34)*

See accompanying notes.

On Behalf of the Board:

Gordon D. Giffin
Director

William D. Anderson
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)	**Common shares**	**Preferred shares**
Balance, Jan. 1, 2010	2,164	–
Net earnings	–	–
Other comprehensive income (loss):		
Losses on translating net assets of foreign operations, net of hedges and of tax	–	–
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	–	–
Net actuarial losses on defined benefit plans, net of tax	–	–
Total comprehensive (loss) income		
Common share dividends	–	–
Preferred share dividends	–	–
Distributions to non-controlling interests	–	–
Common shares issued	40	–
Preferred shares issued	–	293
Effect of share-based payment plans	–	–
Sale of minority interest in Kent Hills 2	–	–
Balance, Dec. 31, 2010	2,204	293
Net earnings	–	–
Other comprehensive (loss) income:		
Losses on translating net assets of foreign operations, net of hedges and of tax	–	–
Net losses on derivatives designated as cash flow hedges, net of tax	–	–
Net actuarial losses on defined benefit plans, net of tax	–	–
Total comprehensive (loss) income		
Common share dividends	–	–
Preferred share dividends	–	–
Distributions to non-controlling interests	–	–
Common shares issued	69	–
Preferred shares issued	–	269
Effect of share-based payment plans	–	–
Balance, Dec. 31, 2011	**2,273**	**562**

1 Refer to Note 26 for details on components of and changes in Accumulated other comprehensive income (loss).

See accompanying notes.

Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
5	495	189	2,853	471	3,324
–	256	–	256	24	280
–	–	(27)	(27)	–	(27)
–	–	43	43	(17)	26
–	–	(20)	(20)	–	(20)
		(4)	252	7	259
–	(319)	–	(319)	–	(319)
–	(1)	–	(1)	–	(1)
–	–	–	–	(62)	(62)
–	–	–	40	–	40
–	–	–	293	–	293
2	–	–	2	–	2
–	–	–	–	15	15
7	431	185	3,120	431	3,551
–	305	–	305	38	**343**
–	–	(1)	(1)	–	**(1)**
–	–	(260)	(260)	(20)	**(280)**
–	–	(26)	(26)	–	**(26)**
		(287)	18	18	**36**
–	(194)	–	(194)	–	**(194)**
–	(15)	–	(15)	–	**(15)**
–	–	–	–	(91)	**(91)**
–	–	–	69	–	**69**
–	–	–	269	–	**269**
2	–	–	2	–	**2**
9	**527**	**(102)**	**3,269**	**358**	**3,627**

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2011**	2010
Operating activities		
Net earnings	**343**	280
Depreciation and amortization *(Note 36)*	**532**	511
Gain on sale of assets	**(16)**	-
Accretion of provisions *(Note 21)*	**19**	18
Decommissioning and restoration costs settled *(Note 21)*	**(33)**	(37)
Deferred income taxes *(Note 10)*	**80**	54
Unrealized gain from risk management activities	**(175)**	(47)
Unrealized foreign exchange loss (gain)	**3**	(3)
Provisions	**22**	-
Asset impairment charges *(Note 8)*	**17**	28
Reserve on collateral *(Notes 14 and 16)*	**18**	-
Equity income, net of distributions received *(Note 7)*	**1**	2
Other non-cash items	**(2)**	(1)
	809	805
Change in non-cash operating working capital balances *(Note 30)*	**(115)**	33
Cash flow from operating activities	**694**	838
Investing activities		
Additions to property, plant, and equipment *(Note 17)*	**(453)**	(808)
Additions to intangibles *(Note 19)*	**(30)**	(29)
Proceeds on sale of property, plant, and equipment	**12**	6
Proceeds on sale of facilities and development projects	**40**	-
Acquisition of the remaining 50% of the Taylor Hydro joint venture *(Note 4)*	**(7)**	-
Proceeds on sale of minority interest in Kent Hills 2 *(Note 11)*	**-**	15
Resolution of certain tax matters *(Note 10)*	**3**	29
Realized losses on financial instruments	**(12)**	(29)
Net (decrease) increase in collateral received from counterparties	**(109)**	47
Net increase in collateral paid to counterparties	**(56)**	(2)
Other	**(3)**	6
Cash flow used in investing activities	**(615)**	(765)
Financing activities		
Net increase (decrease) in borrowings under credit facilities *(Note 22)*	**155**	(400)
Repayment of long-term debt *(Note 22)*	**(234)**	(10)
Issuance of long-term debt *(Note 22)*	**-**	301
Dividends paid on common shares *(Note 24)*	**(191)**	(216)
Dividends paid on preferred shares *(Note 25)*	**(15)**	-
Net proceeds on issuance of common shares *(Note 24)*	**2**	1
Net proceeds on issuance of preferred shares *(Note 25)*	**267**	291
Realized gains on financial instruments	**9**	3
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(61)**	(62)
Decrease in finance lease receivable *(Note 6)*	**3**	2
Other	**(2)**	-
Cash flow used in financing activities	**(67)**	(90)
Cash flow from (used in) operating, investing, and financing activities	**12**	(17)
Effective change in value of foreign cash	**2**	(1)
Increase (decrease) in cash and cash equivalents	**14**	(18)
Cash and cash equivalents, beginning of year	**35**	53
Cash and cash equivalents, end of year	**49**	35
Cash income taxes recovered	**(1)**	(51)
Cash interest paid	**197**	142

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

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 became a subsidiary.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation Segment owns and operates hydro, wind, geothermal, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("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.

II. Energy Trading

The Energy Trading Segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives.

Energy Trading manages available generating capacity as well as the fuel and transmission needs of the Generation Segment by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of all of these activities are included in the Generation Segment.

III. Corporate

The Corporate Segment 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 to the Generation and Energy Trading Segments.

2. Accounting Policies

A. Basis of Preparation and Transition to International Financial Reporting Standards

Effective Jan. 1, 2011, all Canadian publicly accountable enterprises are required to prepare their financial statements using IFRS, issued by the International Accounting Standards Board ("IASB"), and as adopted by the Accounting Standards Board of Canada. IFRS 1 *First-time Adoption of International Financial Reporting Standards* ("IFRS 1") requires that an entity's accounting policies used in its opening statement of financial position and throughout all periods presented in its first IFRS financial statements comply with IFRS effective at the end of its first IFRS reporting period. Accordingly, the IFRS issued and effective as at Dec. 31, 2011 have been applied in preparing the consolidated financial statements as at and for the year ended Dec. 31, 2011, the comparative information presented as at and for the year ended Dec. 31, 2010, and in preparation of the opening IFRS Statement of Financial Position as at Jan. 1, 2010. The impacts of the transition to IFRS for the comparative information are presented in Note 3.

These consolidated financial statements have been prepared by management in compliance with IFRS as issued by the IASB.

The consolidated financial statements have been prepared on a historical cost basis except for financial instruments that are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board of Directors on March 1, 2012.

B. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation, and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiary so as to obtain benefits from its activities, generally indicated by ownership of, directly or indirectly, more than one-half of the voting rights. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

C. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be reliably measured. Revenue from the rendering of services are recognized when criteria ii), iii) and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt hour ("MWh") produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with lease elements are recognized as outlined in Note 2(T).

Trading activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in the Consolidated Statements of Earnings. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

D. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint ventures each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar while the functional currencies of the subsidiary companies and joint ventures' are either the Canadian, U.S., or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rates in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive (Loss) Income ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the net investment as a result of a disposal, partial disposal, or loss of control.

E. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives, and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position from the point when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, 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 nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are removed from the Consolidated Statements of Financial Position when the obligation is discharged, cancelled, or expired.

Derivative instruments that are embedded in financial or non-financial contracts that are not already required to be recognized at fair value are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts and the contract is not measured at fair value. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which are recognized in OCI. Derivatives used in trading activities are described in more detail in Note 2(C).

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. 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.

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 exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific assets and liabilities on the Consolidated Statements of Financial Position or to specific firm commitments or highly probable anticipated transactions.

The Corporation 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. If the above hedge criteria are not met, the derivative is accounted for on the Consolidated Statements of Financial Position 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 amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being 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 for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount 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. 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 is achieved if the derivatives' cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. If 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 to net earnings from AOCI immediately when it is not probable that the forecasted transaction will occur within the time period specified in the hedge documentation.

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 highly probable anticipated transactions denominated in foreign currencies. If the hedging criteria are met, changes in value are reported in OCI or directly in earnings 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. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument 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 disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts, and foreign denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from 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, as appropriate.

F. Cash and Cash Equivalents

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

G. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its 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.

H. Inventory

I. Fuel

The Corporation's inventory balance represents fuel, which is measured at the lower of cost and net realizable value. 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 electricity production as maintenance is performed. Due to the limited number 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 and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Trading

Commodity inventories held in the Energy Trading Segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

I. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably.

The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

The estimate of the useful lives of each component 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 component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Thermal generation	3-50 years
Gas generation	2-30 years
Renewable generation	3-60 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction *(Note 2(U))*. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are amortized over the estimated useful life of the related asset.

J. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally-generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale of the intangible asset, and its probable future economic benefits, are demonstrated. Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any.

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangibles may be determined, for example, with reference to the term of the related contract or license agreement. The estimated useful lives and amortization methods are reviewed at each year-end with the effect of any changes being accounted for prospectively. Intangible assets with indefinite useful lives are not amortized, but are tested for impairment annually.

Intangible assets consist of: power sale contracts with fixed prices higher than market prices at the date of acquisition; coal rights; software; and intangibles under development. Estimated useful lives of intangible assets are as follows:

Software	2-7 years
Power contracts	1-30 years

K. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period the Corporation reviews the net carrying amount of PP&E and finite life intangible assets to determine whether there is any indication that an impairment loss may exist.

Factors that could indicate that an impairment exists include significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or 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 the Corporation 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 a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. When impairment is based on value in use, the Corporation bases its impairment on detailed cash flow budgets and forecasts that cover the asset's useful life. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the asset's recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

L. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but 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 CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs to which the goodwill relates is compared to the carrying amount of the CGUs. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

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 recognized as 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 costs incurred subsequently are included in other assets or PP&E. The appropriateness of the carrying amount of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

N. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred tax is charged or credited to net earnings, except when it relates to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

O. Employee Future Benefits

The Corporation accrues its obligations under employee future benefit plans and the related costs, net of plan assets. The cost of pension and other post-employment benefits, such as health and dental benefits, earned by employees is actuarially determined using the projected unit credit 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, at the beginning of the period, for returns over the life of the benefit obligations. The discount rate used to determine the present value of the defined benefit obligation is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations.

Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions at the end of each interim reporting period. The Corporation determines an estimate of the actuarial gains or losses incurred in that period using updated fair values for plan assets and period-end discount rates for computing the defined benefit liability. Resulting changes in actuarial gains or losses are recognized in OCI in the interim period in which they occur. Past service costs are recognized immediately in net earnings to the extent that the benefits have vested; otherwise, they are amortized on a straight-line basis over the vesting period.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Corporation's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Corporation as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

P. Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, re-measured at each period end, of the expenditures required to settle the present obligation considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Corporation calculates the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E *(Note 2(I))*. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. Where the Corporation expects to receive reimbursement from a third-party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received. Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

Q. Share-Based Payments

The Corporation measures equity-settled stock option awards using the fair value method. Compensation expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled share-based payment award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation costs associated with awards under the Performance Share Ownership Plan ("PSOP") are accrued based on the fair value of each award, the service period completed, and the number of equivalent common shares eligible employees and directors have earned at the statement of financial position date, which is 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 comparative group.

For share-based payments earned under cash-settled phantom stock option plans, a liability, and corresponding compensation cost, is recognized at each statement of financial position date, until final settlement, based on the fair value of each award and the service period completed.

R. Emission Credits and Allowances

Purchased emission credits and allowances are recorded as inventory at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, these amounts are recognized as revenue in the period of recovery.

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

S. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Any impairment is recognized in earnings. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position. Depreciation ceases when an asset is classified as held for sale.

T. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (i.e. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance income. The finance income element of the payments is recognized using a method that results in a constant periodic rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life. Rental income, including contingent rents, from operating leases is recognized over the term of the arrangement and is reflected in revenue on the Consolidated Statements of Earnings. Contingent rent may arise when payments due under the contract are not fixed in amount but vary based on a future factor such as the amount of use or production.

U. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

V. Non-controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used.

Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains controls.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

W. Joint Ventures

A joint venture is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. TransAlta's joint ventures are generally classified as two types: jointly controlled assets and jointly controlled entities.

A jointly controlled asset arises when the joint venturers have joint control or joint ownership of one or more assets contributed to, or acquired for and dedicated to, the purpose of the joint venture. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint venture. The Corporation reports its interests in jointly controlled assets in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues, and expenses in respect of its interest in the joint venture.

In jointly controlled entities, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer is entitled to a share of the net earnings of the jointly controlled entity. The Corporation reports its interests in jointly controlled entities using the equity method. Under the equity method, the investment in the jointly controlled entity is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the jointly controlled entity's net earnings after the date of acquisition. The Corporation's share of net earnings resulting from transactions between the Corporation and the jointly controlled entities are eliminated based on the Corporation's ownership interest. Distributions received from the jointly controlled entities reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities, and contingent liabilities of an acquired jointly controlled entity is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in jointly controlled entities are evaluated for impairment at each statement of financial position date by first assessing whether there is objective evidence that the investment is impaired. Objective evidence could include, for example, such factors as significant financial difficulty of the investee, or information about significant changes with an adverse effect that have taken place in the technological, market, economic, or legal environment in which the investee operates, which may indicate that the cost of the investment may not be recovered. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs to sell.

X. Government Grants

Government grants are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the grant and that the grant will be received. When the grant relates to an expense item, it is recognized in net earnings over the same period in which the related costs or revenues are recognized. When the grant relates to an asset, it is recognized as a reduction of the carrying amount of PP&E and released to earnings as a reduction in depreciation over the expected useful life of the related asset.

Y. Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of consolidated financial statements requires management to make judgments, estimates, and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses, and disclosures of contingent assets and liabilities 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, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

In the process of applying the Corporation's accounting policies, which are described above, management has to make judgments and estimates, about matters that are highly uncertain at the time the estimate is made, that could significantly affect the amounts recognized in the consolidated financial statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset or CGU to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less cost to sell and its value in use. In determining fair value less costs to sell, information about third party transactions for similar assets is used and if none are available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs to sell or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management uses 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, changes to regulations, and transmission capacity or constraints for the remaining life of the plant. These estimates and assumptions are susceptible to change from period to period and 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. Key assumptions used in determining the recoverable amount of the Centralia Coal plant are further explained in Note 8.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant to how the Corporation classifies amounts related to the arrangement as PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the value of certain items of revenue and expense, is dependent upon such classifications. The Corporation has determined that the long-term contract for Fort Saskatchewan is a finance lease.

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation, to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amount recognized for deferred income tax assets and liabilities.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 13. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value. The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility, and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is used in determining whether a cash flow hedge is a highly probable anticipated transaction based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Project Development Costs

Deferred project developments costs are capitalized in accordance with the accounting policy in Note 2(M). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(P) and Note 21. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VII. Useful Life of PP&E

Each significant component of an item of 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, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

VIII. Employee Future Benefits

The Corporation provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors including actual plan experience and estimates and assumptions about future experience.

The liability for post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets;
- the effects of changes to the provisions of the plans; and
- changes in key actuarial assumptions, including anticipated rates of return on plan assets, rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employement benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate.

IX. Other Provisions

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

Z. Accounting Changes

I. Current Year Accounting Changes

a. Change in Estimates – Residual Values

During the first quarter of 2011, management completed a comprehensive review of the residual values of all of TransAlta's generating assets, having regard for, among other things, expectations about the future condition of the assets, metal volumes, as well as other market-related factors. As a result, estimated residual values were revised, resulting in depreciation decreasing by $13 million for the year ended Dec. 31, 2011 compared to 2010.

II. Prior Year Accounting Changes

a. Inventory

During the second quarter of 2010, the Corporation modified its inventory measurement policy for commodity inventories held in its Energy Trading business segment to better reflect the nature of the underlying inventory and the segment's business objectives. Commodity inventories held in the Energy Trading Segment are now measured at fair value less costs to sell, as opposed to the lower of cost and net realizable value. Changes in fair value less costs to sell are recognized in net earnings in the period of change. The effect of this change on current and prior periods was not material. Accordingly, the change has been applied prospectively and prior periods have not been restated.

b. Change in Estimate – Useful Lives

In 2010, management initiated a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, TransAlta's economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market-related factors. Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $26 million for the year ended Dec. 31, 2010 compared to 2009.

III. Future Accounting Changes

a. Consolidated Financial Statements

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements* ("IFRS 10"), which replaces International Accounting Standard 27 *Consolidated and Separate Financial Statements* ("IAS 27") and Standing Interpretations Committee Interpretation 12 *Consolidation - Special Purpose Entities* ("SIC-12"). IFRS 10 provides a revised definition of control so that a single control model can be applied to all entities for consolidation purposes.

b. Joint Arrangements

In May 2011, the IASB issued IFRS 11 *Joint Arrangements*, which supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. IFRS 11 provides for a principle-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its joint arrangements. IFRS 11 also generally requires the use of the equity method of accounting for interests in joint ventures. Improvements in disclosure requirements are intended to allow investors to gain a better understanding of the nature, extent, and financial effects of the activities that an entity carries out through joint arrangements.

c. Disclosure of Interests in Other Entities

In May 2011, the IASB issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in consolidated and unconsolidated entities, such as subsidiaries, joint arrangements, associates, and unconsolidated structured entities (special purpose entities).

d. Investments in Associates and Joint Ventures and Separate Financial Statements

In May 2011, two existing standards, IAS 28 *Investments in Associates and Joint Ventures* and IAS 27 *Separate Financial Statements*, were amended. The amendments are not significant, and result from the issuance of IFRS 10, IFRS 11, and IFRS 12.

The requirements of the preceding new standards and amendments to existing standards outlined in a. through d., are effective for annual periods beginning on or after Jan. 1, 2013. The disclosure requirements of IFRS 12 may be incorporated into the financial statements earlier than Jan. 1, 2013. However, early adoption of the other standards is only permitted if all five are applied at the same time. The Corporation is currently assessing the impact of adopting these new standards and amendments on the consolidated financial statements, and does not expect the impact to be significant.

e. Fair Value Measurements

In June 2011, the IASB issued IFRS 13 *Fair Value Measurements*, which establishes a single source of guidance for all fair value measurements required by other IFRS; clarifies the definition of fair value; and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability, or its own equity instrument at fair value. IFRS 13 is effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. The Corporation is currently assessing the impact of adopting IFRS 13 on the consolidated financial statements.

f. Presentation of Financial Statements

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are at some point reclassified from OCI to net earnings or not. The amendments to IAS 1 are effective for annual periods beginning on or after July 1, 2012. Earlier application is permitted. As a result of the amendment, the items presented within the Consolidated Statements of Other Comprehensive Income will be reorganized to comply with the required groupings.

g. Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefit*s to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require a new presentation approach that improves the visibility of the different types of gains and losses arising from defined benefit plans, as follows: service cost is presented in net earnings; finance cost is presented as part of finance costs in net earnings; and remeasurements of the net defined benefit asset or liability are recognized immediately in OCI. The amendments eliminate the option to defer the recognition of actuarial gains and losses, known as the 'corridor method'. The disclosure requirements are enhanced to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. The amendments to IAS 19 are effective for annual periods beginning on or after Jan. 1, 2013. Earlier application is permitted. The Corporation is currently assessing the impact of adopting the amendments to IAS 19 on the consolidated financial statements.

h. Financial Instruments

In November 2009, the IASB issued IFRS 9 *Financial Instruments,* which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or fair value through profit or loss or through OCI depending on the basis of the entity's business model for managing the financial asset, and the contractual cash flow characteristics of the financial asset.

In October 2010, the IASB issued additions to IFRS 9 regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

In December 2011, the IASB amended the effective date of these requirements, which are now effective for annual periods beginning on or after Jan. 1, 2015, and must be applied on a modified retrospective basis. Earlier adoption is permitted. The December amendment also provided relief from restating comparative periods and from the associated disclosures required under IFRS 7 *Financial Instruments: Disclosures*. The Corporation is currently assessing the impact of adopting these amendments on the consolidated financial statements.

i. Stripping Costs in the Production Phase of a Surface Mine

In October 2011, the IFRS Interpretations Committee issued Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine* ("IFRIC 20"), which clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods. The Interpretation is effective for annual periods beginning on or after Jan. 1, 2013, with earlier application permitted. The Corporation is currently assessing the impact of adopting IFRIC 20 on the consolidated financial statements.

j. Offsetting Financial Assets and Liabilities

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation*. The amendments are intended to clarify certain aspects of the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements on offsetting. The IASB also amended IFRS 7 to require information about all recognized financial instruments that are set off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set off under IAS 32.

The amendments to IAS 32 are effective for annual periods beginning on or after Jan. 1, 2014. However, the new offsetting disclosure requirements are effective for annual periods beginning on or after Jan. 1, 2013 and interim periods within those annual periods. The amendments need to be provided retrospectively to all comparative periods. The Corporation is currently assessing the impact of adopting these amendments on the consolidated financial statements.

3. First-Time Adoption of IFRS

IFRS 1 provides specific requirements for an entity's initial adoption of IFRS.

IFRS 1 requires that an entity's accounting policies used in its opening statement of financial position and throughout all periods presented in its first IFRS financial statements comply with IFRS effective at the end of its first IFRS reporting period. Accordingly, the IFRS issued and effective as of Dec. 31, 2011, have been applied in preparing the consolidated financial statements as at and for the years ended Dec. 31, 2011 and 2010 and in preparing the opening IFRS Statement of Financial Position as at Jan. 1, 2010.

In certain circumstances, IFRS 1 provides for exceptions to, or exemptions from, retrospective application of certain IFRS. The following IFRS 1 exemptions and elections have been utilized by the Corporation:

- The cumulative net foreign exchange losses related to the translation of foreign operations, net of foreign exchange amounts on related net investment hedges, has been reset to zero at Jan. 1, 2010.
- The Corporation has determined whether arrangements existing at the date of transition to IFRS contain, or are considered to be, a lease on the basis of facts and circumstances existing at that date. Where the same determination as required by IFRS was made at a different date in accordance with Canadian Generally Accepted Accounting Principles ("the Corporation's previous GAAP" or "Canadian GAAP"), arrangements reviewed under the Corporation's previous GAAP have not been reassessed for IFRS transition. TransAlta is required to review arrangements outside of the scope of the Corporation's previous GAAP and has determined that one of the agreements contains a finance lease.
- IFRIC 1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* has not been applied retrospectively to determine the cost of decommissioning assets. The simplified method permitted under IFRS 1 has been applied.
- IFRS 2 *Share-based Payment* has been applied to equity instruments that were granted on or after Nov. 7, 2002 but that had not vested by the Corporation's transition date of Jan. 1, 2010.
- IFRS 3 *Business Combinations* has not been applied retrospectively to business combinations occurring prior to the date of transition to IFRS. Accordingly, assets and liabilities acquired in business combinations prior to Jan. 1, 2010 continue to be measured and recorded at the carrying amounts determined under the Corporation's previous GAAP.
- The Corporation's Australian subsidiaries adopted IFRS effective Jan. 1, 2005. Where IFRS adopted by the Corporation may have permitted re-measurements of the Australian subsidiaries' assets and liabilities, the Corporation has elected not to do so.
- IAS 23 *Borrowing Costs* has been applied prospectively to borrowing costs relating to qualifying assets for which the commencement date for capitalization is on or after the transition date.
- Amounts capitalized under the Corporation's previous GAAP, such as allowance for funds used during construction and general overheads for certain PP&E assets that were operated in rate-regulated environments, have not been restated to comply with cost as determined by IAS 16 *Property, Plant and Equipment*. The carrying amount of these items under the Corporation's previous GAAP was determined following prescribed regulations and has been elected as deemed cost.
- The Corporation has elected to recognize, at the date of transition, all cumulative actuarial gains and losses associated with its defined benefit pension and other post-employment benefit plans.
- Certain IAS 19 disclosures have been applied prospectively from the date of transition to IFRS.

Differences between the Corporation's previous GAAP and its IFRS financial position as at Jan. 1, 2010 and as at Dec. 31, 2010, its financial performance for the year ended Dec. 31, 2010, and its cash flows for the year ended Dec. 31, 2010, are outlined in the following tables and explanatory notes:

A. Reconciliation of Financial Position at Jan. 1, 2010

Consolidated Statement of Financial Position

(in millions of Canadian dollars)

As at Jan. 1, 2010	Canadian GAAP	IAS 21	IFRS 3
Cash and cash equivalents	82	–	–
Accounts receivable	421	–	–
Current portion of finance lease receivable	–	–	–
Collateral paid	27	–	–
Prepaid expenses	18	–	–
Risk management assets	144	–	–
Income taxes receivable	39	–	–
Inventory	90	–	–
Assets held for sale	–	–	–
	821	–	–
Investments	–	–	–
Long-term receivables	49	–	–
Finance lease receivable	–	–	–
Property, plant, and equipment			
Cost	11,701	–	(104)
Accumulated depreciation	(4,142)	–	1
	7,559	–	(103)
Goodwill	434	–	87
Intangible assets	344	–	(10)
Deferred income tax assets	234	–	–
Risk management assets	224	–	–
Other assets	121	–	–
Total assets	9,786	–	(26)
Accounts payable and accrued liabilities	521	–	2
Decommissioning and other provisions	–	–	–
Collateral received	86	–	–
Risk management liabilities	45	–	–
Income taxes payable	10	–	–
Future income tax liabilities	45	–	–
Dividends payable	61	–	–
Current portion of long-term debt	31	–	–
Current portion of asset retirement obligations	32	–	–
	831	–	2
Long-term debt	4,411	–	–
Decommissioning and other provisions	–	–	–
Deferred income tax liabilities	662	–	(29)
Risk management liabilities	78	–	–
Deferred credits and other long-term liabilities	147	–	–
Asset retirement obligations	250	–	–
Non-controlling interests	478	–	–
Equity			
Common shares	2,164	–	–
Contributed surplus	5	–	–
Retained earnings	634	(63)	1
Accumulated other comprehensive income	126	63	–
Equity attributable to shareholders	2,929	–	1
Non-controlling interests	–	–	–
Total equity	2,929	–	1
Total liabilities and equity	9,786	–	(26)

IAS 16	IAS 19	IAS 31	IAS 37	IFRIC 4/ IAS 17	IAS 36	Reclass	IFRS
–	–	(29)	–	–	–	–	**53**
–	–	(16)	–	–	–	–	**405**
–	–	–	–	2	–	–	**2**
–	–	–	–	–	–	–	**27**
–	–	–	–	–	–	–	**18**
–	–	–	–	–	–	2	**146**
–	–	(1)	–	–	–	–	**38**
–	–	–	–	–	–	–	**90**
–	–	–	–	–	–	4	**4**
–	–	(46)	–	2	–	6	**783**
–	–	202	–	–	–	–	**202**
–	–	–	–	–	–	–	**49**
–	–	–	–	48	–	–	**48**
200	–	(366)	(22)	(55)	(283)	(240)	**10,831**
(85)	–	103	20	25	196	128	**(3,754)**
115	–	(263)	(2)	(30)	(87)	(112)	**7,077**
–	–	(74)	–	–	–	–	**447**
–	–	(149)	–	–	–	108	**293**
(3)	7	–	4	–	22	(35)	**229**
–	–	–	–	–	–	(2)	**222**
–	(18)	–	–	–	–	–	**103**
112	(11)	(330)	2	20	(65)	(35)	**9,453**
–	–	(12)	–	–	2	(29)	**484**
–	–	–	–	–	–	61	**61**
–	–	–	–	–	–	–	**86**
–	–	–	–	–	–	–	**45**
–	–	(1)	–	–	–	–	**9**
–	–	–	–	–	–	(45)	**–**
–	–	–	–	–	–	–	**61**
–	–	(22)	–	–	–	–	**9**
–	–	–	–	–	–	(32)	**–**
–	–	(35)	–	–	2	(45)	**755**
–	–	(180)	–	–	–	–	**4,231**
–	–	–	–	–	–	287	**287**
26	(22)	(95)	(6)	3	(7)	10	**542**
–	–	–	–	–	–	–	**78**
–	89	–	–	–	8	(8)	**236**
–	–	(5)	34	–	–	(279)	**–**
2	–	(16)	–	10	(3)	(471)	**–**
–	–	–	–	–	–	–	**2,164**
–	–	–	–	–	–	–	**5**
84	(78)	1	(26)	7	(65)	–	**495**
–	–	–	–	–	–	–	**189**
84	(78)	1	(26)	7	(65)	–	**2,853**
–	–	–	–	–	–	471	**471**
84	(78)	1	(26)	7	(65)	471	**3,324**
112	(11)	(330)	2	20	(65)	(35)	**9,453**

B. Reconciliation of Financial Position as at Dec. 31, 2010

Consolidated Statement of Financial Position

(in millions of Canadian dollars)

As at Dec. 31, 2010	Canadian GAAP	IAS 21
Cash and cash equivalents	58	–
Accounts receivable	428	–
Current portion of finance lease receivable	–	–
Collateral paid	27	–
Prepaid expenses	10	–
Risk management assets	265	–
Income taxes receivable	19	–
Inventory	53	–
Assets held for sale	–	–
	860	–
Investments	–	–
Finance lease receivable	–	–
Property, plant, and equipment		
Cost	11,706	–
Accumulated depreciation	(4,129)	–
	7,577	–
Assets held for sale	60	–
Goodwill	517	–
Intangible assets	304	–
Deferred income tax assets	240	–
Risk management assets	208	–
Other assets	127	–
Total assets	9,893	–
Short-term debt	1	–
Accounts payable and accrued liabilities	503	–
Decommissioning and other provisions	–	–
Collateral received	126	–
Risk management liabilities	35	–
Income taxes payable	8	–
Future income tax liabilities	77	–
Dividends payable	130	–
Current portion of long-term debt	255	–
Current portion of asset retirement obligations	38	–
Liabilities held for sale	–	–
	1,173	–
Long-term debt	3,979	–
Decommissioning and other provisions	–	–
Deferred income tax liabilities	630	–
Risk management liabilities	123	–
Deferred credits and other long-term liabilities	169	–
Liabilities held for sale	3	–
Asset retirement obligations	204	–
Non-controlling interests	435	–
Equity		
Common shares	2,204	–
Preferred shares	293	–
Contributed surplus	7	–
Retained earnings	533	(62)
Accumulated other comprehensive income	140	62
Equity attributable to shareholders	3,177	–
Non-controlling interests	–	–
Total equity	3,177	–
Total liabilities and equity	9,893	–

IAS 16	IAS 19	IAS 31	IAS 37	IFRIC 4/ IAS 17	IAS 36	Reclass	IFRS
–	–	(23)	–	–	–	–	35
–	–	(16)	–	–	–	–	412
–	–	–	–	2	–	–	2
–	–	–	–	–	–	–	27
–	–	–	–	–	–	–	10
–	–	–	–	–	–	3	268
–	–	(1)	–	–	–	–	18
–	–	–	–	–	–	–	53
–	–	–	–	–	–	60	60
–	–	(40)	–	2	–	63	885
–	–	190	–	–	–	–	190
–	–	–	–	46	–	–	46
208	–	(365)	26	(55)	(219)	(261)	11,040
(108)	–	129	(12)	28	196	150	(3,746)
100	–	(236)	14	(27)	(23)	(111)	7,294
–	–	–	–	–	–	(60)	-
–	–	(70)	–	–	–	–	447
–	–	(127)	–	–	–	111	288
(3)	6	–	2	–	–	(67)	178
–	–	–	–	–	–	(3)	205
–	(25)	–	–	–	–	–	102
97	(19)	(283)	16	21	(23)	(67)	9,635
–	–	(1)	–	–	–	–	-
–	–	(7)	–	–	1	(15)	482
–	–	–	–	–	–	54	54
–	–	–	–	–	–	–	126
–	–	–	–	–	–	–	35
–	–	–	–	–	–	–	8
–	–	–	–	–	–	(77)	-
–	–	–	–	–	–	–	130
–	–	(18)	–	–	–	–	237
–	–	–	–	–	–	(38)	-
–	–	–	–	–	–	3	3
–	–	(26)	–	–	1	(73)	1,075
–	–	(156)	–	–	–	–	3,823
–	–	–	–	–	–	256	256
22	(30)	(84)	(7)	3	(6)	10	538
–	–	–	–	–	–	–	123
–	110	–	–	–	(1)	(9)	269
–	–	–	–	–	–	(3)	-
–	–	(5)	48	–	–	(247)	-
2	–	(16)	–	11	–	(432)	-
–	–	–	–	–	–	–	2,204
–	–	–	–	–	–	–	293
–	–	–	–	–	–	–	7
73	(80)	4	(25)	7	(19)	–	431
–	(19)	–	–	–	2	–	185
73	(99)	4	(25)	7	(17)	–	3,120
–	–	–	–	–	–	431	431
73	(99)	4	(25)	7	(17)	431	3,551
97	(19)	(283)	16	21	(23)	(67)	9,635

Explanations of the adjustments from the Corporation's previous GAAP to IFRS related to the Consolidated Statements of Financial Position as at Jan. 1, 2010 and Dec. 31, 2010 in the above-noted tables are as follows:

I. IAS 21 *The Effects of Changes in Foreign Exchange Rates*

Retrospective application of IAS 21 would require identification of the foreign exchange gains or losses for each foreign operation and recalculation of these gains or losses on each foreign operation's IFRS transition adjustments. IFRS 1 provides that a first-time adopter need not comply with these IAS 21 requirements. Accordingly, the cumulative net foreign exchange losses for all foreign operations, including the foreign exchange amounts arising on related net investment hedges, net of tax, has been reset to zero on transition. Net gains or losses arising subsequent to transition are recognized in OCI in accordance with the Corporation's accounting policy outlined in Note 2(D) and Note 2(E).

II. IFRS 3 *Business Combinations*

IFRS 3 requires that when the initial accounting for a business combination is incomplete and adjustments are subsequently made to the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date, the adjustments are made retrospectively. The Corporation's previous GAAP required prospective application of the adjustments from the date the adjustments were determined. Accordingly, the adjustments on transition relate to the retrospective application of the Corporation's final allocation of the Canadian Hydro Developers, Inc. ("Canadian Hydro") consideration transferred *(Note 4)*.

III. IAS 16 *Property, Plant and Equipment*

IAS 16 requires the capitalization of costs associated with planned major maintenance and inspection activities. Planned major maintenance includes inspection, repair and maintenance of existing components, and the replacement of existing components. Some of these amounts were expensed under the Corporation's previous GAAP. On transition, the unamortized amount of previously expensed planned major maintenance and inspection costs has been capitalized as part of PP&E. Costs incurred subsequently for planned major maintenance activities are capitalized in the period maintenance activities occur and amortized on a straight-line basis over the term until the next major maintenance event.

IV. IAS 19 *Employee Benefits*

Under the Corporation's previous GAAP, the corridor approach was used to account for actuarial gains and losses on defined benefit pension and other post-employment benefit plans. Under the corridor approach, some actuarial gains and losses remained unrecognized. Application of the corridor approach under IAS 19 would require the cumulative actuarial gains and losses from inception of each plan to the transition date to be split into recognized and unrecognized amounts. IFRS 1 permits recognition of all cumulative actuarial gains and losses at the date of transition to IFRS, even if the corridor approach is not used thereafter. Actuarial gains and losses arising subsequent to the transition date are recognized in OCI in accordance with the Corporation's accounting policy outlined in Note 2(O).

V. IAS 31 *Interests in Joint Ventures*

Under the Corporation's previous GAAP, all joint ventures were accounted for using the proportionate consolidation method. Under IFRS, parties to a joint venture recognize their contractual rights and obligations arising from the venture. Joint ventures are classified into three types: jointly controlled assets, jointly controlled operations, and jointly controlled entities. TransAlta's joint ventures are classified as jointly controlled assets or jointly controlled entities under IFRS.

For jointly controlled assets, the accounting requirements under IFRS generally result in the same accounting as proportionate consolidation under the Corporation's previous GAAP. Under IFRS, a venturer can choose to recognize its interest in a jointly controlled entity using either proportionate consolidation or the equity method. TransAlta accounts for its interest in jointly controlled entities using the equity method. Under the equity method, TransAlta's investments in its CE Gen and Wailuku jointly controlled entities are reflected as a single line item, entitled "Investments", on the Consolidated Statements of Financial Position, and the Corporation's share of the income is reflected as equity earnings or loss in the Consolidated Statements of Earnings. TransAlta's share of the cash and cash equivalents, and the cash flow changes, of these equity accounted investments are no longer presented within each line item of the operating, investing, or financing activities in the Consolidated Statements of Cash Flows. Instead, cash distributions received are presented as an operating activity and cash returns of invested capital, or cash invested, are presented as an investing activity.

VI. IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*

IAS 37 requires provisions to be measured at the present value of the amounts expected to be paid where the effect of the time value of money is material. Provisions must be reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including consideration of the effects of changes in the market-based, risk-adjusted discount rate, where applicable. The Corporation's previous GAAP did not require consideration of changes in the market-based, risk-adjusted discount rate at each period end. The Corporation's provisions for decommissioning and restoration, and other provisions, have been measured at transition and at subsequent period ends using a current market-based interest rate at those dates, adjusted for the risks specific to the liabilities.

Under IFRIC 1 the amount of a change in a decommissioning and restoration liability resulting from i) changes in the estimated timing or amount of cash flows and ii) changes in the current market-based, risk-adjusted discount rate, must be added to, or deducted from, the cost of the related asset.

Retrospective application of IAS 37 and IFRIC 1 would have required the Corporation to reconstruct a historical record of all such adjustments that would have been made in the past. Use of the IFRS 1 exemption permits the amount included in the cost of the related asset to be estimated by discounting the liability back to the date when the liability first arose using management's best estimate of the average historical risk-adjusted discount rates that would have applied over the intervening period. Accumulated depreciation on this asset amount has been calculated on the basis of the current estimate of the useful life of the asset, using the IFRS depreciation policies outlined in Note 2(I).

VII. IAS 17 *Leases*/IFRIC 4 *Determining whether an Arrangement contains a Lease*

Under IAS 17, a lease is defined as an agreement whereby the lessor conveys to the lessee, in return for a payment, or a series of payments, the right to use a specific asset for an agreed period of time. IFRIC 4 provides guidance on how to determine whether an arrangement that is not structured as a lease contains, or is considered to be, a lease as defined in IAS 17. As a result of the specific terms and conditions of the Corporation's Fort Saskatchewan long-term contract, it has been determined to be a finance lease. Certain other PPAs and long-term contracts have been determined to be, or contain, operating leases.

a. Finance Leases

Where the Corporation determines that the contractual provisions of the PPA or other long-term contract have resulted in the customer assuming the principal risks and rewards of ownership of the plant, the arrangement is a finance lease. The assets subject to the lease have been removed from the Corporation's PP&E and the amounts due from the lessees under the related finance leases recorded in the Consolidated Statements of Financial Position as financial assets, classified as finance lease receivables. The payments considered to be part of the leasing arrangement are apportioned between the finance lease receivable and finance income.

b. Operating Leases

Where the Corporation determines that the contractual provisions of the PPA or other long-term contract have resulted in the Corporation retaining the principal risks and rewards of ownership of the plant, the arrangement is an operating lease. The assets subject to the lease continue to be recorded as PP&E and depreciated over their useful lives.

PPAs and other long-term contracts that are not considered to be, or contain, leases, result in the continued recognition of PP&E and revenues, consistent with the Corporation's previous GAAP.

VIII. IAS 36 *Impairment of Assets*

Under IAS 36, undiscounted future cash flows are not used to initially assess for impairment, as under the Corporation's previous GAAP. Instead, when an indication of impairment exists, the asset's carrying amount is compared to the greater of its value in use or fair value less normal costs to sell. As a result, on transition, the Corporation recognized pre-tax impairment losses of $101 million ($98 million after deducting the amount that was attributed to the non-controlling interest) that were comprised of $70 million related to the natural gas fleet and $31 million related to the coal fleet. The natural gas fleet impairment results from lower forecast pricing at one of the merchant facilities and the sale of one of the Corporation's contracted facilities. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and is primarily due to the Corporation's shift in managing the coal-fired generation facilities on a unit pair basis and the shut down due to the physical state of the boilers such that the units cannot be economically restored to service under the terms of the PPA. The recoverable amounts of impaired assets were based on fair value derived through the use of discounted cash flow analysis from the Corporation's long-range forecasts and other market-based assumptions, as considered appropriate. Due to IFRS transition impairments, the timing of recognition of impairment losses in 2010 differed under IFRS versus the Corporation's previous GAAP.

IX. IFRS Reclassifications

- Under IFRS, mineral rights and reserves and software are accounted for pursuant to IAS 38 *Intangible Assets*, whereas under the Corporation's previous GAAP, they were classified as PP&E.
- Under IAS 12 *Income Taxes,* future income taxes are referred to as deferred income tax assets and liabilities, which must be classified as non-current, whereas the Corporation's previous GAAP permitted both current and non-current classification.
- Under IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*, non-current assets meeting the definition of held for sale are classified as current assets, whereas the Corporation's previous GAAP permitted non-current classification.
- Under IAS 37, the Corporation has classified its provisions for decommissioning and restoration activities together with all other provisions, whereas under its previous GAAP such provisions were reflected as a separate line item on the Consolidated Statements of Financial Position.
- Under IAS 1, non-controlling interests are classified as part of Equity.

C. Reconciliation of Earnings

Consolidated Statement of Earnings

(in millions of Canadian dollars)

For the year ended Dec. 31, 2010	Canadian GAAP[1]	IAS 21
Revenues	2,819	–
Fuel and purchased power	1,202	–
	1,617	–
Operations, maintenance, and administration	634	–
Depreciation and amortization	459	–
Taxes, other than income taxes	27	–
	1,120	–
	497	–
Finance lease income	–	–
Equity income	–	–
Foreign exchange gain (loss)	10	(2)
Asset impairment charges	(89)	–
Net interest expense	(178)	–
Earnings (loss) before non-controlling interests and income taxes	240	(2)
Income tax expense (recovery)	1	(3)
Net earnings (loss)	239	1

1 Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

2 Includes impacts of other IFRS adjustment for IAS 16 and IAS 37.

Explanations of the adjustments from the Corporation's previous GAAP to IFRS related to the Consolidated Statement of Earnings for the year ended Dec. 31, 2010 are as follows:

I. IAS 21 *The Effects of Changes in Foreign Exchange Rates*

On transition to IFRS, the cumulative net foreign exchange losses related to the translation of foreign operations was reset to nil. As a result, the amount reclassified from AOCI to net earnings in 2010 under IFRS due to the wind-up of a foreign subsidiary differed from the Corporation's previous GAAP.

II. IFRS 3 *Business Combinations*

IFRS 3 requires subsequent adjustments to the provisional allocation of consideration transferred recognized at the acquisition date to be reflected retrospectively as at the acquisition date, whereas the Corporation's previous GAAP requires prospective application. As a result, depreciation and amortization recognized in 2010 under the Corporation's previous GAAP was recognized as a transition date adjustment under IFRS.

III. IAS 16 *Property, Plant and Equipment*

IAS 16 requires the capitalization of costs associated with planned major maintenance and inspection activities. Some of these amounts were expensed under the Corporation's previous GAAP. The adjustment represents the capitalization of expenditures incurred in the period that were expensed under the Corporation's previous GAAP and the depreciation of expenditures capitalized on transition to IFRS.

IV. IAS 19 *Employee Benefits*

As a result of the recognition of unrealized net actuarial losses on transition to IFRS, pension and other post-employment expenses under IFRS differ from the Corporation's previous GAAP amounts.

IFRS 3	IAS 16	IAS 19	IAS 31[2]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
–	–	–	(136)	–	(10)	–	**2,673**
–	–	–	(11)	(3)	–	(3)	**1,185**
–	–	–	(125)	3	(10)	3	**1,488**
–	(67)	2	(59)	–	–	–	**510**
1	81	–	(49)	(16)	(3)	(9)	**464**
–	–	–	–	–	–	–	**27**
1	14	2	(108)	(16)	(3)	(9)	**1,001**
(1)	(14)	(2)	(17)	19	(7)	12	**487**
–	–	–	–	–	8	–	**8**
–	–	–	7	–	–	–	**7**
–	–	–	–	–	–	–	**8**
–	–	–	–	–	–	61	**(28)**
–	–	–	17	(17)	–	–	**(178)**
(1)	(14)	(2)	7	2	1	73	**304**
–	(3)	–	4	1	–	24	**24**
(1)	(11)	(2)	3	1	1	49	**280**

V. IAS 31 *Interests in Joint Ventures*

Under the Corporation's previous GAAP, joint ventures were accounted for using the proportionate consolidation method. IAS 31 permits the use of the proportionate consolidation method or the equity method for joint ventures classified as jointly controlled entities. The Corporation has adopted the equity method for its interests in the CE Gen and Wailuku jointly controlled entities. The adjustment represents the reclassification of the Corporation's proportionate share of CE Gen's and Wailuku's revenue and expenses from each respective line item to a single line item entitled "Equity income".

VI. IAS 37 *Provisions*

Amounts expensed as accretion of provisions under IFRS differ compared to accretion under the Corporation's previous GAAP as IFRS requires provisions to be revalued at the end of each reporting period using a current market-based, risk-adjusted discount rate. In addition, accretion expense is recognized as a finance cost under IFRS and is included in net interest expense, whereas under the Corporation's previous GAAP, accretion expense was recognized in fuel and purchased power or depreciation and amortization.

VII. IAS 17 *Leases*/IFRIC 4 *Determining whether an Arrangement contains a Lease*

Under IFRS, the Corporation's Fort Saskatchewan long-term contract is considered a finance lease arrangement. The adjustment represents the reversal of i) revenues recognized under the Corporation's previous GAAP for the delivery of goods and services and; ii) depreciation on the assets subject to the finance lease; and the recognition of finance lease income earned under the finance lease arrangement.

VIII. IAS 36 *Impairment of Assets*

Due to the recognition of asset impairment losses on transition to IFRS, depreciation during 2010 under IFRS was lower than under the Corporation's previous GAAP. In addition, transportation expenses included in fuel and purchased power were lower in 2010 under IFRS due to the recognition at transition of an onerous contract associated with one of the impaired assets.

D. Reconciliation of Total Comprehensive Income

Consolidated Statement of Comprehensive Income

(in millions of Canadian dollars)

For the year ended Dec. 31, 2010	Canadian GAAP[1]	IAS 21
Net earnings (loss)	239	1
Other comprehensive (loss) income		
(Losses) gains on translating net assets of foreign operations	(60)	–
Gains on financial instruments designated as hedges of foreign operations, net of tax	33	–
Reclassification of gains on translation of foreign operations to net earnings, net of tax	(2)	(1)
Gains on derivatives designated as cash flow hedges, net of tax	147	–
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax	8	–
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax	(129)	–
Net actuarial losses on defined benefit plans, net of tax	–	–
Other comprehensive (loss) income	(3)	(1)
Total comprehensive income (loss)	236	–
Total comprehensive income (loss) attributable to:		
Common shareholders	233	–
Non-controlling interests	3	–
	236	–

1 Under the Corporation's previous GAAP, net earnings (loss) was arrived at after deducting or adding back the non-controlling interests' share of net earnings (loss). Under IFRS, net earnings (loss) as presented on the Consolidated Statements of Earnings, includes the non-controlling interests' share. Total net earnings (loss) is then attributed to both shareholders and non-controlling interests.

2 Includes impacts of other IFRS adjustment for IAS 16 and IAS 37.

Explaining the adjustments from the Corporation's previous GAAP to IFRS related to the Consolidated Statement of Comprehensive Income for the year ended Dec. 31, 2010 are as follows:

I. IAS 21 *The Effects of Changes in Foreign Exchange Rates*

On transition to IFRS, the cumulative net foreign exchange losses related to the translation of foreign operations was reset to nil. As a result, the amount reclassified from AOCI to net earnings in 2010 under IFRS due to the wind-up of a foreign subsidiary differed from the Corporation's previous GAAP.

II. IAS 19 *Employee Benefits*

Under IFRS, the Corporation's policy is to recognize actuarial gains and losses in OCI in the period in which they occur. Under the Corporation's previous GAAP the corridor method was used, which did not require recognition of actuarial gains or losses in OCI, but instead required recognition in net earnings over time when certain conditions were met.

III. IAS 36 *Impairment of Assets*

Due to the recognition of asset impairment losses on transition to IFRS, translation differences arose in respect of foreign operations.

IFRS 3	IAS 16	IAS 19	IAS 31[2]	IAS 37	IFRIC 4/ IAS 17	IAS 36	IFRS
(1)	(11)	(2)	3	1	1	49	**280**
–	–	1	–	–	–	2	**(57)**
–	–	–	–	–	–	–	**33**
–	–	–	–	–	–	–	**(3)**
–	–	–	–	–	–	–	**147**
–	–	–	–	–	–	–	**8**
–	–	–	–	–	–	–	**(129)**
–	–	(20)	–	–	–	–	**(20)**
–	–	(19)	–	–	–	2	**(21)**
(1)	(11)	(21)	3	1	1	51	**259**
(1)	(11)	(21)	3	1	–	48	**252**
–	–	–	–	–	1	3	**7**
(1)	(11)	(21)	3	1	1	51	**259**

E. Consolidated Statement of Cash Flows Impact

The transition to IFRS changed the presentation of several items on the Consolidated Statement of Cash Flows. The most significant of these changes is the effect of applying the equity method of accounting to the Corporation's interest in jointly controlled entities, versus the proportionate consolidation method used under the Corporation's previous GAAP. TransAlta's share of the cash and cash equivalents and the cash flow changes of equity accounted jointly controlled entities are no longer presented within each line item of the operating, investing, or financing activities sections of the Consolidated Statement of Cash Flows, and instead, cash distributions received from equity accounted jointly controlled entities are presented as an operating activity and cash returns of invested capital and additional cash invested in equity accounted jointly controlled entities are presented as an investing activity. The capitalization of costs associated with planned major maintenance and inspection activities that were expensed under the Corporation's previous GAAP will result in these cash expenditures being reported as an investing activity under IFRS. Under the Corporation's previous GAAP these expenditures impacted cash flow from operations.

4. Acquisitions and Disposals

A. Acquisitions

On Nov. 1, 2011, the Corporation purchased the remaining 50 per cent of the Taylor Hydro joint assets from Capital Power, the joint venture partner, for $7 million. As the Corporation acquired control of the overall business, TransAlta has remeasured the entire asset at the acquisition-date fair value.

In 2009, TransAlta acquired Canadian Hydro through the purchase of all of the issued and outstanding shares of Canadian Hydro.

During the fourth quarter of 2010, the preliminary allocation of consideration transferred was revised to reflect the results of management's assessment of value. The significant adjustments between the preliminary and final allocation of consideration transferred were primarily due to the finalization of the fair values of property, plant, and equipment and intangible assets. The adjustments to the allocation of consideration transferred were applied retrospectively to the date of acquisition. The resulting adjustments and final allocation of consideration transferred are highlighted below:

	Preliminary allocation	Adjustments	Final allocation
Assets			
Cash	19	–	19
Accounts receivable	25	–	25
Prepaid expenses	5	–	5
Intangible assets	198	(10)	188
Property, plant, and equipment	1,291	(104)	1,187
Total assets acquired	1,538	(114)	1,424
Liabilities			
Accounts payable and accrued liabilities	54	2	56
Current risk management liabilities	6	–	6
Long-term risk management liabilities	34	–	34
Long-term debt	931	–	931
Deferred income tax liabilities	29	(29)	–
Provisions	3	–	3
Total liabilities assumed	1,057	(27)	1,030
Net assets acquired	481	(87)	394
Goodwill	304	87	391
Total consideration transferred	**785**	**–**	**785**

B. Disposals

During 2011, the Corporation sold its biomass facility located in Grande Prairie. The sale was effective Sept. 1, 2011 and closed on Oct. 1, 2011. As a result, the Corporation realized a pre-tax gain of $9 million.

On Dec. 20, 2010, TransAlta Cogeneration, L.P. ("TA Cogen"), a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. At Dec. 31, 2010, all associated assets and liabilities were classified as held for sale under the Generation Segment. The sale was effective Jan. 1, 2011 and closed April 2011, and resulted in a pre-tax gain of $3 million.

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2011		2010	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**721**	**–**	891	–
Purchased power	**183**	**–**	253	–
Salaries and benefits	**3**	**289**	4	276
Depreciation	**40**	**–**	37	–
Other operating expenses	**–**	**256**	–	234
Total	**947**	**545**	1,185	510

6. Leases

A. The Corporation as Lessor

I. Finance Leases

The amounts receivable under finance leases are as follows:

As at	Dec. 31, 2011		Dec. 31, 2010	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**10**	**9**	10	9
Second to fifth years inclusive	**41**	**25**	41	25
More than five years	**31**	**11**	42	14
	82	**45**	93	48
Less: unearned finance income	**37**	**–**	45	–
Total finance lease receivable	**45**	**45**	48	48
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease receivables	**3**		2	
Non-current finance lease receivables	**42**		46	
	45		48	

As at	Jan. 1, 2010	
	Minimum lease payments	Present value of minimum lease payments
Within one year	10	9
Second to fifth years inclusive	41	25
More than five years	52	16
	103	50
Less: unearned finance income	53	–
Total finance lease receivable	50	50
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables	2	
Non-current finance lease receivables	48	
	50	

The interest rate inherent in the lease is fixed at the contract date for the entire lease term and is approximately 17 per cent per annum.

II. Operating Leases

Several of the Corporation's PPAs and other long-term contracts meet the criteria of operating leases. Total contingent rentals related to these contracts and recognized as revenue in the Consolidated Statements of Earnings for the year ended Dec. 31, 2011 was $162 million (2010 – $205 million).

B. The Corporation as Lessee

I. Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment.

During the year ended Dec. 31, 2011, $12 million (2010 – $12 million) was recognized as an expense in the Consolidated Statements of Earnings in respect of these operating leases. No sublease payments were received or made, nor were any contingent rental payments made, in respect of these operating leases.

Future minimum lease payments required under non-cancellable operating leases are as follows:

2012	16
2013	11
2014	11
2015	11
2016	10
2017 and thereafter	42
Total minimum lease payments	**101**

7. Investments

The Corporation's investment in jointly controlled entities, accounted for using the equity method, consists of its investments in CE Gen and Wailuku.

The change in investments is as follows:

Balance, Jan. 1, 2010	202
Equity income	7
Distributions received	(9)
Change in foreign exchange rates	(10)
Balance, Dec. 31, 2010	190
Equity income	14
Distributions received	(15)
Change in foreign exchange rates	4
Balance, Dec. 31, 2011	**193**

Summarized information on the results of operations and financial position relating to the Corporation's pro-rata interests in its jointly controlled entities is as follows:

Year ended Dec. 31	2011	2010
Results of operations		
Revenues	**133**	136
Expenses	**(119)**	(129)
Proportionate share of net earnings	**14**	7

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Financial position			
Current assets	**42**	42	48
Long-term assets	**423**	437	486
Current liabilities	**(29)**	(28)	(36)
Long-term liabilities	**(229)**	(246)	(280)
Non-controlling interests	**(14)**	(15)	(16)
Proportionate share of net assets	**193**	190	202

8. Asset Impairment Charges

A. Asset Impairment Charges

During 2011, the Corporation recorded a pre-tax impairment charge of $17 million related to four Generation assets within the renewables fleet that were part of the acquisition of Canadian Hydro, in order to write the assets down to their estimated fair values less cost to sell. The fair value estimates are derived from the long-range forecasts for the assets and prices evidenced in the marketplace. Two of the assets were impaired due to operational factors that impacted their useful lives, resulting in an impairment charge of $5 million. The impairment charges on the other two assets, totalling $12 million, resulted from the Corporation's annual comprehensive impairment assessment and reflect lower forecast pricing at these merchant facilities.

During 2010, the Corporation recorded a pre-tax impairment charge of $28 million ($21 million after deducting the amount that is attributed to the non-controlling interest) on certain Generation assets, consisting of a $7 million charge against the natural gas fleet and a $21 million charge against the coal fleet. The natural gas fleet impairment reflects the sale of the Corporation's 50 per cent interest in the Meridian facility, which was attributed to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at the Sundance facility and resulted from the shut down due to the physical state of the boilers such that the units cannot be economically restored to service under the terms of the PPA.

B. Asset Impairment Review – Centralia Coal

In 2011, the TransAlta Energy Bill (the "Bill") was signed into law in the State of Washington. The Bill, and a Memorandum of Agreement (the "MoA") signed on Dec. 23, 2011, which is part of the Bill, provide a framework to transition from coal-fired energy produced at the Corporation's Centralia Coal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of the shut down of the units and the removal of restrictions on the terms of power contracts that the Corporation can enter into.

At Dec. 31, 2011, the Corporation completed an assessment of whether the carrying amount of the Centralia Coal plant was recoverable from the future cash flows expected to be derived from the plant's operations. Based on this assessment, which included assumptions regarding the Corporation's ability to enter into power contracts longer than five years as permitted in the Bill and MoA, the Corporation concluded that the plant was not impaired.

However, given the significance of the contracting assumptions, it is possible that actual outcomes could differ from these assumptions and that a material adjustment to the $786 million carrying amount of the plant could arise within the next fiscal year.

The Corporation has established a dedicated commercial team to pursue long-term contracts for the plant, and as a result, expects to be able to more clearly determine the impact of this uncertainty on the future cash flows of the plant in 2012. If the Corporation achieves its long-term contracting targets for the plant in 2012, it does not expect that an impairment loss will result.

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2011	2010
Interest on debt	**228**	226
Interest income	**–**	(18)
Capitalized interest *(Note 17)*	**(31)**	(48)
Ineffectiveness on fair value hedges	**(1)**	–
Interest expense	**196**	160
Accretion of provisions *(Note 21)*	**19**	18
Net interest expense	**215**	178

The Corporation capitalizes interest during the construction phase of growth capital projects. The capitalized interest in 2011 relates primarily to Keephills Unit 3. Capitalized interest in 2010 relates primarily to Keephills Unit 3, Ardenville, and the Kent Hills expansion.

10. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2011	2010
Earnings before income taxes	**449**	304
Equity income	**(14)**	(7)
Net earnings attributable to non-controlling interests	**(38)**	(24)
Adjusted earnings before income taxes	**397**	273
Statutory Canadian federal and provincial income tax rate *(%)*	**26.5**	28.0
Expected income tax expense	**105**	76
(Decrease) increase in income taxes resulting from:		
Lower effective foreign tax rates	**(3)**	(15)
Resolution of uncertain tax matters	**-**	(30)
Statutory and other rate differences	**(1)**	(10)
Other	**5**	3
Income tax expense	**106**	24
Effective tax rate *(%)*	**27**	9

II. Components of Income Tax Expense

The components of income tax expense (recovery) are as follows:

Year ended Dec. 31	2011	2010
Current tax expense	**26**	-
Adjustments in respect of current income tax of previous year	**-**	(30)
Deferred income tax expense related to the origination and reversal of temporary differences	**78**	53
Deferred tax expense arising from uncertain tax positions	**2**	-
Deferred tax expense arising from the writedown, or reversal of a previous writedown, of a deferred tax asset	**-**	1
Income tax expense	**106**	24

Year ended Dec. 31	2011	2010
Current tax expense (recovery)	**26**	(30)
Deferred income tax expense	**80**	54
Income tax expense	**106**	24

During 2010, TransAlta recognized and received a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense in 2010 was reduced by $14 million as a result of tax related interest recoveries.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2011	2010
Income tax expense (recovery) related to:		
Net impact related to cash flow hedges	**(101)**	25
Net impact related to net investment hedges	**(5)**	6
Net actuarial losses	**(9)**	(7)
Preferred share issuance costs	**(2)**	(2)
Income tax (recovery) expense reported in equity	**(117)**	22

C. Consolidated Statements of Financial Position

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

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Net operating and capital loss carryforwards	**453**	382	297
Future decommissioning and restoration costs	**99**	95	85
Property, plant, and equipment	**(912)**	(824)	(718)
Risk management assets and liabilities, net	**(72)**	(113)	(82)
Employee future benefits and compensation plans	**59**	50	48
Allowance for doubtful accounts	**19**	18	19
Other deductible temporary differences	**39**	32	38
Net deferred income tax liability	**(315)**	(360)	(313)

The Corporation recognizes tax losses to recover current tax of a previous period when it is probable that the benefit will flow to the Corporation, as a result of future probable earnings and tax strategies, and it can be reliably measured. The deferred tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings. The assumptions used in the estimate of future earnings are based on the Corporation's long range forecasts.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Deferred income tax assets	**176**	178	229
Deferred income tax liabilities	**(491)**	(538)	(542)
Net deferred income tax liability	**(315)**	(360)	(313)

D. Contingencies

As of Dec. 31, 2011, the Corporation had recognized a net liability of $43 million (2010 – $44 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

Balance, Jan. 1, 2010	(111)
Increase as a result of tax positions taken during a prior period	(14)
Decrease as a result of settlements with taxation authorities	92
Other tax contingencies	(11)
Balance, Dec. 31, 2010	(44)
Increase as a result of tax positions taken during a prior period	(5)
Decrease as a result of settlements with taxation authorities	6
Balance, Dec. 31, 2011	**(43)**

11. Non-Controlling Interests

A. Consolidated Statements of Earnings

Year ended Dec. 31	2011	2010
Stanley Power's interest (49.99%) in TransAlta Cogeneration, L.P.	**35**	23
Natural Forces Technologies Inc.'s interest (17%) in Kent Hills	**3**	1
Total	**38**	24

B. Consolidated Statements of Financial Position

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Stanley Power's interest in TransAlta Cogeneration, L.P.	**317**	388	443
Natural Forces Technologies Inc.'s interest in Kent Hills	**41**	43	28
Total	**358**	431	471

The change in non-controlling interests is as follows:

Balance, Jan. 1, 2010	471
Distributions paid	(62)
Non-controlling interests portion of net earnings	24
Non-controlling interests portion of OCI	(17)
Acquisition of minority interest in Kent Hills [1]	15
As at Dec. 31, 2010	431
Distributions paid [2]	(91)
Non-controlling interests portion of net earnings	38
Non-controlling interests portion of OCI	(20)
As at Dec. 31, 2011	**358**

1 *During 2010, Natural Forces Technologies, Inc. exercised its option to purchase a 17 per cent interest in the Kent Hills expansion project for proceeds of $15 million. The pre-tax gain related to this transaction did not have a significant impact on net earnings in 2010.*
2 *Includes a $30 million non-cash distribution related to the sale of the Meridian facility.*

C. Consolidated Statements of Cash Flows

Distributions paid by subsidiaries to non-controlling interests are as follows:

Year ended Dec. 31	2011	2010
TransAlta Cogeneration, L.P.	**57**	60
Kent Hills	**4**	2
Total	**61**	62

12. Accounts Receivable

As at	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Gross accounts receivable	**588**	458	454
Allowance for doubtful accounts *(Note 32)*	**(47)**	(46)	(49)
Net accounts receivable	**541**	412	405

The change in allowance for doubtful accounts is as follows:

Balance, Jan. 1, 2010	49
Change in foreign exchange rates	(3)
Balance, Dec. 31, 2010	46
Change in foreign exchange rates	1
Balance, Dec. 31, 2011	**47**

13. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at fair value or amortized cost *(Note 2(E))*. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at Dec. 31, 2011

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	49	–	49
Accounts receivable	–	–	541	–	541
Collateral paid	–	–	45	–	45
Finance lease receivable					
Current	–	–	3	–	3
Long-term	–	–	42	–	42
Risk management assets					
Current	10	381	–	–	391
Long-term	35	64	–	–	99
Long-term receivable	–	–	18	–	18
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	463	463
Collateral received	–	–	–	16	16
Dividends payable	–	–	–	67	67
Risk management liabilities					
Current	71	137	–	–	208
Long-term	128	14	–	–	142
Long-term debt[1]	–	–	–	4,037	4,037

1 *Includes current portion.*

Carrying value of financial instruments as at Dec. 31, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	35	–	35
Accounts receivable	–	–	412	–	412
Collateral paid	–	–	27	–	27
Finance lease receivable					
Current	–	–	2	–	2
Long-term	–	–	46	–	46
Risk management assets					
Current	186	82	–	–	268
Long-term	204	1	–	–	205
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	482	482
Collateral received	–	–	–	126	126
Dividends payable	–	–	–	130	130
Risk management liabilities					
Current	5	30	–	–	35
Long-term	123	–	–	–	123
Long-term debt [1]	–	–	–	4,060	4,060

1 *Includes current portion.*

Carrying value of financial instruments as at Jan. 1, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	53	–	53
Accounts receivable	–	–	405	–	405
Collateral paid	–	–	27	–	27
Finance lease receivable					
Current	–	–	2	–	2
Long-term	–	–	48	–	48
Risk management assets					
Current	130	16	–	–	146
Long-term	219	3	–	–	222
Long-term receivable	–	–	49	–	49
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	484	484
Collateral received	–	–	–	86	86
Dividends payable	–	–	–	61	61
Risk management liabilities					
Current	28	17	–	–	45
Long-term	75	3	–	–	78
Long-term debt [2]	–	–	–	4,240	4,240

2 *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 inputs 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 below:

a. 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 fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are 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 on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also 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.

c. Level III

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

In limited circumstances, the Corporation 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 for individual non-standard deals and structured products, 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.

TransAlta also has various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III. These contracts are for a specified price with creditworthy counterparties.

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

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation Segments in relation to trading activities and certain contracting activities.

The following table summarizes the key factors impacting the fair value of the energy trading risk management assets and liabilities by classification level during the year ended Dec. 31, 2011:

	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 (liabilities) at Dec. 31, 2010	–	319	(20)	(1)	53	–	(1)	372	(20)
Changes attributable to:									
Market price changes on existing contracts	–	(66)	(19)	(13)	47	31	(13)	(19)	12
Market price changes on new contracts	–	13	–	13	66	2	13	79	2
Contracts settled	–	(187)	(1)	1	(48)	–	1	(235)	(1)
Discontinued hedge accounting on certain contracts	–	(169)	26	–	169	(26)	–	–	–
Net risk management assets (liabilities) at Dec. 31, 2011	**–**	**(90)**	**(14)**	**–**	**287**	**7**	**–**	**197**	**(7)**
Additional Level III information:									
Change in fair value included in OCI			(20)			–			(20)
Total gain included in earnings before income taxes			1			–			1
Unrealized gain included in earnings before income taxes relating to net assets and liabilities held at Dec. 31, 2011			–			33			33

To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of the Energy Trading and Generation business segments.

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, 2011 is estimated to be +/- $33 million (Dec. 31, 2010 – $14 million, Jan. 1, 2010 – $24 million). Where an internally developed fundamental price forecast is used, reasonable alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonable alternate fundamental price forecasts unavailable.

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

		2012	2013	2014	2015	2016	2017 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	(13)	(22)	(22)	(15)	(12)	(6)	(90)
	Level III	(8)	(6)	–	–	–	–	(14)
Non-hedges	Level I	1	(1)	–	–	–	–	–
	Level II	212	48	27	–	–	–	287
	Level III	19	3	3	2	1	(21)	7
Total	Level I	1	(1)	–	–	–	–	–
	Level II	199	26	5	(15)	(12)	(6)	197
	Level III	11	(3)	3	2	1	(21)	(7)
Total net assets (liabilities)		**211**	**22**	**8**	**(13)**	**(11)**	**(27)**	**190**

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt, and the net investment in foreign operations.

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the year ended Dec. 31, 2011:

	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 (liabilities) assets at Dec. 31, 2010	–	(37)	–	–	1	–	–	(36)	–
Changes attributable to:									
Market price changes	–	25	–	–	–	–	–	25	–
New contracts	–	(34)	–	–	(1)	–	–	(35)	–
Contracts settled	–	(4)	–	–	–	–	–	(4)	–
Net risk management liabilities at Dec. 31, 2011	**–**	**(50)**	**–**	**–**	**–**	**–**	**–**	**(50)**	**–**

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

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

		2012	2013	2014	2015	2016	2017 and thereafter	Total
Hedges	Level I	–	–	–	–	–	–	–
	Level II	(40)	(8)	(2)	(23)	(2)	25	(50)
	Level III	–	–	–	–	–	–	–
Total net (liabilities) assets		**(40)**	**(8)**	**(2)**	**(23)**	**(2)**	**25**	**(50)**

The fair value of financial liabilities measured at other than fair value is as follows:

	Fair value[1]				Total carrying value
	Level I	Level II	Level III	Total	
Long-term debt – Dec. 31, 2011[2]	**–**	**4,324**	**–**	**4,324**	**4,037**
Long-term debt – Dec. 31, 2010[2]	–	4,279	–	4,279	4,060
Long-term debt – Jan. 1, 2010[2]	–	4,303	–	4,303	4,240

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, finance lease receivable, long-term receivable, accounts payable and accrued liabilities, collateral received, and dividends payable).*

2 *Includes current portion.*

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are 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 Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the year is as follows:

As at	Dec. 31, 2011	Dec. 31, 2010
Unamortized gain (loss) at beginning of year	**1**	(1)
New inception gains	**8**	3
Amortization recorded in net earnings during the year	**(5)**	(1)
Unamortized gain at end of year	**4**	1

14. Risk Management Activities

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	Dec. 31, 2011					Dec. 31, 2010	Jan. 1, 2010
	Net investment hedges	**Cash flow hedges**	**Fair value hedges**	**Not designated as a hedge**	**Total**	Total	Total
Risk management assets							
Energy trading							
Current	**-**	**9**	**-**	**381**	**390**	264	146
Long-term	**-**	**9**	**-**	**64**	**73**	186	205
Total energy trading risk management assets	**-**	**18**	**-**	**445**	**463**	450	351
Other							
Current	**1**	**-**	**-**	**-**	**1**	4	-
Long-term	**-**	**1**	**25**	**-**	**26**	19	17
Total other risk management assets	**1**	**1**	**25**	**-**	**27**	23	17
Risk management liabilities							
Energy trading							
Current	**-**	**30**	**-**	**137**	**167**	30	30
Long-term	**-**	**92**	**-**	**14**	**106**	69	50
Total energy trading risk management liabilities	**-**	**122**	**-**	**151**	**273**	99	80
Other							
Current	**5**	**36**	**-**	**-**	**41**	5	15
Long-term	**-**	**36**	**-**	**-**	**36**	54	28
Total other risk management liabilities	**5**	**72**	**-**	**-**	**77**	59	43
Net energy trading risk management assets (liabilities)	**-**	**(104)**	**-**	**294**	**190**	351	271
Net other risk management assets (liabilities)	**(4)**	**(71)**	**25**	**-**	**(50)**	(36)	(26)
Net total risk management assets (liabilities)	**(4)**	**(175)**	**25**	**294**	**140**	315	245

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

Long-Term Debt

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (Dec. 31, 2010 – U.S.$820 million, Jan. 1, 2010 – U.S.$1,100 million), and borrowings under a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2010 – U.S.$300 million, Jan. 1, 2010 – U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in foreign operations.

The Corporation hedges its net investment in foreign operations with U.S. denominated borrowings, cross-currency interest rate swaps, and foreign currency forward sale contracts as outlined below:

Cross-Currency Interest Rate Swaps

Outstanding cross-currency interest rate swaps used as part of the net investment hedge is as follows:

As at	**Dec. 31, 2011**			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	-	**-**	**-**	-	-	-	AUD34	(2)	2010

Foreign Currency Contracts

Outstanding foreign currency forward sale contracts used as part of the net investment hedge are as follows:

As at	**Dec. 31, 2011**			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity	Notional amount	Fair value liability	Maturity
	AUD185	**(4)**	**2012**	AUD180	(1)	2011	AUD120	(2)	2010
	USD135	**-**	**2012**	USD120	1	2011	-	-	-

ii. Effect on the Consolidated Statement of Comprehensive Income

For the year ended Dec. 31, 2011, a net after-tax loss of $1 million (Dec. 31, 2010 – loss of $24 million), relating to the translation of the Corporation's net investment in 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 Statement of Earnings, Consolidated Statement of Comprehensive Income, and the Consolidated Statements of Financial Position:

Year ended Dec. 31, 2011

Financial instruments in net investment hedging relationships	**Pre-tax (loss) recognized in OCI**	**Location of (gain) reclassified from OCI**	**Pre-tax (gain) reclassified from OCI**
Long-term debt	**(23)**	Foreign exchange	**-**
Foreign currency contracts	**(15)**	Foreign exchange	**-**
OCI impact	**(38)**	**OCI impact**	**-**

Year ended Dec. 31, 2010

Financial instruments in net investment hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) reclassified from OCI	Pre-tax (gain) reclassified from OCI
Long-term debt	68	Foreign exchange	(3)
Foreign currency contracts	(29)	Foreign exchange	-
OCI impact	39	OCI impact	(3)

b. Cash Flow Hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at Dec. 31, 2011, were as follows:

(Thousands)	**Dec. 31, 2011**		Dec. 31, 2010		Jan. 1, 2010	
Type	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**7,817**	**4**	28,814	10	28,989	–
Natural gas *(GJ)*	**2,032**	**39,022**	1,925	32,751	2,163	360
Oil *(gallons)*	**–**	**6,300**	–	12,432	–	25,074

During 2011, unrealized pre-tax gains of $207 million (2010 – $43 million gain) were released from AOCI and recognized in earnings due to certain hedges being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices that will change between now and the time the underlying hedged transactions are expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the gains associated with these contracts would have been recorded in net earnings in the period in which they settle, the majority of which will occur during 2012. As these gains have already been recognized in earnings in the current period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

The Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Dec. 31, 2011, cumulative gains of $92 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur, or at the time it is determined that it is not possible for the underlying transaction to occur.

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Receipts and Expenditures

The Corporation uses forward foreign exchange contracts to hedge a portion of its future foreign denominated receipts and expenditures as follows:

As at	**Dec. 31, 2011**				Dec. 31, 2010			
	Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
	250	**USD233**	**(8)**	**2012-2017**	217	USD200	(12)	2011-2017
	USD8	**8**	**–**	**2012**	USD8	8	–	2011
	103	**EUR74**	**(6)**	**2012**	–	–	–	–

As at	Jan. 1, 2010			
	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
	91	USD78	(8)	2010
	USD14	15	–	2010
	AUD4	USD3	–	2010

Foreign Exchange Forward Contracts on Foreign Denominated Debt

Outstanding foreign exchange forward purchase contracts used to manage foreign exchange exposure on debt not designated as a net investment hedge are as follows:

As at	Dec. 31, 2011			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	USD300	**(5)**	**2012**	USD300	(7)	2012	–	–	–
	USD300	**(5)**	**2013**	USD300	(7)	2013	–	–	–

Cross-Currency Interest Rate Swap

TransAlta uses cross-currency interest rate swaps to manage foreign exchange risk exposures on foreign denominated debt not designated as a net investment hedge as follows:

As at	Dec. 31, 2011			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	USD500	**(22)**	**2015**	USD500	(27)	2015	USD500	(16)	2015

iii. *Interest Rate Risk Management*

The Corporation has outstanding forward start interest rate swaps with fixed rates ranging from 2.75 per cent to 3.43 per cent.

As at	Dec. 31, 2011			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	USD300	**(25)**	**2012**	–	–	–	USD300[1]	(8)	2010

1 *These swaps were closed out upon the issuance of the U.S. $300 million senior notes during the first quarter of 2010 and the resulting losses have been included in AOCI and will be amortized to earnings over the original 10-year term of the swaps.*

iv. *Effect on the Consolidated Statement of Comprehensive Income*

Forward sale and purchase commodity contracts, foreign exchange contracts, cross-currency interest rate swaps, as well as interest rate 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.

The following tables summarize the impact of cash flow hedges on the Consolidated Statement of Comprehensive Income, Consolidated Statement of Earnings, and the Consolidated Statements of Financial Position:

Year ended Dec. 31, 2011

	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 (gain) recognized in earnings**	**Pre-tax (gain) recognized in earnings**
Commodity contracts	**(92)**	Revenue	**(43)**	Revenue	**(207)**
Foreign exchange contracts on project hedges	**(3)**	Property, plant and equipment	**-**	Property, plant and equipment	**-**
Foreign exchange contracts on U.S. debt hedges	**3**	Foreign exchange (gain) loss	**-**	Foreign exchange (gain) loss	**-**
Cross-currency interest rate swaps	**7**	Foreign exchange (gain) loss	**(23)**	Foreign exchange (gain) loss	**-**
Forward start interest rate contracts	**(25)**	Interest expense	**2**	Interest expense	**-**
OCI impact	**(110)**	**OCI impact**	**(64)**	**Net earnings impact**	**(207)**

Year ended Dec. 31, 2010

	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 (gain) reclassified from OCI	Pre-tax (gain) recognized in earnings
Commodity contracts	282	Revenue	(191)	Revenue	(43)
Foreign exchange contracts on project hedges	(15)	Property, plant, and equipment	11	Property, plant and equipment	-
Foreign exchange contracts on U.S. debt hedges	(14)	Foreign exchange (gain) loss	39	Foreign exchange (gain) loss	-
Cross-currency interest rate swaps	(10)	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Forward start interest rate contracts	(9)	Interest expense	1	Interest expense	-
OCI impact	234	OCI impact	(140)	Net earnings impact	(43)

Over the next 12 months, the Corporation estimates that $38 million 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.

c. Fair Value Hedges

i. 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 outlined below *(Note 22)*:

As at	**Dec. 31, 2011**			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset (liability)	Maturity
	-	**-**	**-**	100	2	2011	100	7	2011
	-	**-**	**-**	USD100	3	2013	USD50	(1)	2013
	USD150	**25**	**2018**	USD200	16	2018	USD100	7	2018

Including the interest rate swaps above, 23 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2010 – 25 per cent, Jan. 1, 2010 – 31 per cent).

ii. Effect on the Consolidated Statement of Comprehensive Income

The following table summarizes the impact and location of fair value hedges, including any ineffective portion, on the Consolidated Statement of Earnings:

Year ended Dec. 31		**2011**	2010
Derivatives in fair value hedging relationships	**Location of gain (loss) on the Consolidated Statement of Earnings**		
Interest rate contracts	Net interest expense	**4**	8
Long-term debt	Net interest expense	**(3)**	(8)
Net earnings impact		**1**	–

II. Non-Hedges

The Corporation enters into various derivative transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as at fair value through profit or loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management

The Corporation enters into certain commodity transactions that are classified as at fair value through profit or loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported as revenue in the period the change occurs. The Corporation's outstanding energy trading derivative instruments that are not designated as hedging instruments were as follows:

(Thousands)	**Dec. 31, 2011**		Dec. 31, 2010		Jan. 1, 2010	
Type	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**56,374**	**47,133**	26,553	24,924	14,107	14,844
Natural gas *(GJ)*	**1,007,959**	**1,030,710**	633,483	640,731	323,793	309,764
Transmission *(MWh)*	**-**	**2,908**	–	7,535	–	4,852
Oil *(gallons)*	**-**	**6,552**	–	5,040	–	–

b. 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. Outstanding cross-currency interest rate swaps are as follows:

As at	**Dec. 31, 2011**			Dec. 31, 2010			Jan. 1, 2010		
	Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
	-	**-**	**-**	-	-	-	AUD13	(2)	2010

c. 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 at fair value through profit or loss, and changes in the fair values associated with these transactions are recognized in net earnings.

Outstanding notional amounts and fair values associated with these forward contracts are as follows:

As at	**Dec. 31, 2011**				Dec. 31, 2010			
	Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
	37	**AUD36**	**-**	**2012**	20	AUD20	1	2011
	19	**USD19**	**-**	**2012**	165	USD161	(4)	2011

As at	Jan. 1, 2010			
	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
	USD13	14	-	2010
	178	USD168	(1)	2010

d. Total Return Swaps

The Corporation 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 chosen. 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.

e. Effect on the Consolidated Statement of Comprehensive Income

The Corporation utilizes a variety of derivatives in its 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 at fair value through profit or loss. The net realized and unrealized gains or losses from changes in the fair value of derivatives are reported in earnings in the period the change occurs. For the year ended Dec. 31, 2011, the Corporation recognized a net unrealized gain of $123 million (Dec. 31, 2010 – gain of $33 million).

Foreign exchange derivatives associated with other risk management activities that are not designated as hedges are also classified as at fair value through profit or loss, with the net gain or loss recorded in foreign exchange gain (loss) on the Consolidated Statements of Earnings. For the year ended Dec. 31, 2011, a loss of $4 million (Dec. 31, 2010 – nil) was recognized, comprised of a net unrealized gain of $3 million (Dec. 31, 2010 – $2 million gain) and a net realized loss of $7 million (Dec. 31, 2010 – $2 million loss).

B. 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 the Corporation's expected own use requirements and 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 Energy Trading 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, 2011 associated with the Corporation's proprietary energy trading activities was $5 million (Dec. 31, 2010 – $5 million, Jan. 1, 2010 – $3 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.

TransAlta has entered into various financial 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 and where able has designated these as cash flow hedges for accounting purposes.

As a result, changes in market prices associated with these 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 AOCI, 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, 2011 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $5 million (Dec. 31, 2010 – $52 million, Jan. 1, 2010 – $45 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or for 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, 2011 associated with these transactions was $9 million (Dec. 31, 2010 – $6 million, Jan. 1, 2010 – 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 payments received under the 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, 2011 and 2010, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, outstanding as at the date of the Statements of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2011**		2010	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]
50 basis point change	**4**	**(8)**	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, the U.S. dollar, and the Australian dollar, 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, 2011 and 2010, due to changes in foreign exchange rates associated with financial instruments outstanding as at the date of the Statements of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that a six cent (2010 – six cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2011**		2010	
Currency	**Net earnings decrease**[2]	**OCI gain**[2, 3]	Net earnings (decrease) increase[2]	OCI gain[2, 3]
USD	**(4)**	**11**	(4)	9
AUD	**–**	**–**	1	–
EUR	**–**	**3**	–	–
Total	**(4)**	**14**	(3)	9

2 These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
3 The foreign exchange impacts related to financial instruments used as hedging instruments in 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.

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, 2011:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	93	7	**100**
Risk management assets	94	6	**100**

The Corporation's maximum exposure to credit risk at Dec. 31, 2011, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Statements of Financial Position. 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 *(Note 32)* and including the fair value of open trading, net of any collateral held, at Dec. 31, 2011 was $38 million (Dec. 31, 2010 – $43 million, Jan. 1, 2010 – $63 million).

At Dec. 31, 2011, 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 has evaluated the risk of default related to this counterparty to be minimal.

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 12.

III. Liquidity Risk

Liquidity risk relates to the Corporation's 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 better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong financial position 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 net financial liabilities is as follows:

	2012	2013	2014	2015	2016	2017 and thereafter	Total
Accounts payable and accrued liabilities	463	–	–	–	–	–	463
Collateral received	16	–	–	–	–	–	16
Debt[1]	316	622	209	1,167	29	1,680	4,023
Energy trading risk management (assets) liabilities[2]	(211)	(22)	(8)	13	11	27	(190)
Other risk management liabilities (assets)[2]	40	8	2	23	2	(25)	50
Interest on long-term debt	205	191	164	125	111	843	1,639
Dividends payable	67	–	–	–	–	–	67
Total	**896**	**799**	**367**	**1,328**	**153**	**2,525**	**6,068**

1 *Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.*
2 *Net risk management assets and liabilities.*

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2011, the Corporation provided $45 million (Dec. 31, 2010 – $27 million, Jan. 1, 2010 – $27 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.

II. Financial Assets Held as Collateral

At Dec. 31, 2011, the Corporation received $16 million (Dec. 31, 2010 – $126 million, Jan. 1, 2010 – $86 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their 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.

III. Reserve on Collateral

In October of 2011, MF Global Holdings Ltd. filed for bankruptcy protection in the United States. MF Global Holdings Ltd. is the parent company of MF Global Inc., which was used by TransAlta as a broker-dealer for certain commodity transactions. MF Global Inc. has not filed for bankruptcy but, under the U.S. Securities Investor Protection Act, the Securities Investor Protection Corp. is overseeing a liquidation of the broker-dealer to return assets to customers. A trustee has been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of TransAlta's collateral relates to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and is subject to a dispute between the U.S. Trustee and the U.K. administrator. TransAlta had net collateral of approximately $36 million with MF Global Inc. and due to the uncertainty of collection, TransAlta has recognized an $18 million reserve against the collateral that had been posted. The net amount of the collateral has been reclassified to a long-term asset.

IV. 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, 2011 the Corporation had posted collateral of $62 million (Dec. 31, 2010 – $17 million, Jan. 1, 2010 – $37 million) in the form of letters of credit, on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $72 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2011.

15. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which also includes natural gas, is valued at fair value less costs to sell. The classifications are as follows:

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Coal	**78**	47	86
Natural gas	**5**	5	4
Purchased emission credits	**2**	1	–
Total	**85**	53	90

The increase in coal inventory at Dec. 31, 2011 compared to Dec. 31, 2010 is primarily due to the delayed Keephills Unit 3 start up and the extended outage at Sundance Unit 6.

The change in inventory is as follows:

Balance, Jan. 1, 2010	90
Net consumed	(36)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2010	53
Net additions	30
Change in foreign exchange rates	2
Balance, Dec. 31, 2011	**85**

No inventory is pledged as security for liabilities.

For the years ended Dec. 31, 2011 and 2010, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

16. Long-Term Receivable

In 2011, TransAlta had net collateral of approximately $36 million with MF Global Inc. at the time a trustee has been appointed to take control of, and liquidate the assets of MF Global Inc. and return client collateral. Due to the uncertainty of collection, TransAlta has recognized an $18 million reserve against the collateral that had been posted with MF Global Inc. The net amount is reflected as a long-term receivable.

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million. The appeal decision from the Federal Court was received on Jan. 20, 2012, and the ruling was in TransAlta's favour. The Crown has 60 days from the date of judgment to appeal the decision. If no appeal is filed, TransAlta will receive the $11 million in 2012.

17. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of property, plant, and equipment is as follows:

	Land	Thermal generation
Cost		
As at Jan. 1, 2010	69	4,837
Additions	–	–
Disposals	–	(77)
Asset impairment charges	–	(17)
Revisions and additions to decommissioning and restoration costs	–	2
Transfers to held for sale	–	–
Change in foreign exchange rates	–	(59)
Wabamun decomissioning	–	(280)
Resolution of certain tax matters	–	–
Transfers	2	195
As at Dec. 31, 2010	71	4,601
Additions	–	1
Disposals	–	(1)
Asset impairment charges	–	–
Revisions and additions to decommissioning and restoration costs	–	12
Change in foreign exchange rates	–	28
Retirement of assets	–	(70)
Acquisitions	–	–
Transfers	3	1,002
As at Dec. 31, 2011	**74**	**5,573**
Accumulated depreciation		
As at Jan. 1, 2010	–	2,321
Depreciation	–	237
Disposals	–	(62)
Change in foreign exchange rates	–	(21)
Wabamun decomissioning	–	(267)
Transfers to held for sale	–	–
Transfers	–	4
As at Dec. 31, 2010	–	2,212
Depreciation	–	244
Disposals	–	–
Change in foreign exchange rates	–	11
Retirement of assets	–	(63)
Transfers	–	–
As at Dec. 31, 2011	**–**	**2,404**
Carrying amount		
As at Jan. 1, 2010	69	2,516
As at Dec. 31, 2010	71	2,389
As at Dec. 31, 2011	**74**	**3,169**

The Corporation capitalized $31 million of interest to PP&E in 2011 (2010 – $48 million) at a weighted average rate of 5.34 per cent (2010 – 5.04 per cent).

In 2011, the Corporation wrote down certain capital spares to their estimated recoverable amount, resulting in a $4 million pre-tax increase in the depreciation expense of the Generation Segment.

Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other	Total
1,826	2,059	796	1,030	214	10,831
(7)	6	3	796	10	808
(7)	(2)	(2)	–	(4)	(92)
(7)	–	(4)	–	–	(28)
5	4	1	–	–	12
(89)	–	–	–	–	(89)
20	–	(3)	(2)	–	(44)
–	–	(74)	–	–	(354)
(11)	–	–	–	–	(11)
63	360	203	(842)	26	7
1,793	2,427	920	982	246	11,040
–	–	–	448	4	453
(3)	(1)	(1)	–	(1)	(7)
–	(17)	–	–	–	(17)
2	6	7	–	–	27
7	–	1	–	–	36
(23)	(4)	(8)	–	(5)	(110)
–	10	–	–	–	10
67	85	26	(1,234)	39	(12)
1,843	**2,506**	**945**	**196**	**283**	**11,420**
662	294	424	–	53	3,754
105	76	32	–	9	459
(5)	(2)	(1)	–	(4)	(74)
7	–	(2)	–	1	(15)
–	–	(75)	–	–	(342)
(29)	–	–	–	–	(29)
(7)	–	(2)	–	(2)	(7)
733	368	376	–	57	3,746
98	84	41	–	10	477
–	(1)	(1)	–	–	(2)
4	–	1	–	–	16
(19)	(2)	(6)	–	–	(90)
(14)	(1)	–	–	–	(15)
802	**448**	**411**	**–**	**67**	**4,132**
1,164	1,765	372	1,030	161	7,077
1,060	2,059	544	982	189	7,294
1,041	**2,058**	**534**	**196**	**216**	**7,288**

18. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisition, as follows:

As at	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Energy Trading	**30**	30	30
Renewables	**417**	417	417
Total goodwill	**447**	447	447

In assessing whether goodwill is impaired, the carrying amount of CGUs (including goodwill) is compared with the recoverable amount of the CGU. The recoverable amount is the higher of fair value less costs to sell and value in use. The impairment review for goodwill was conducted during the fourth quarter of 2011. The recoverable amounts exceeded the carrying amounts of the CGUs and there was no impairment of goodwill.

Estimates Used to Measure Recoverable Amounts of Goodwill – Renewables

The Corporation determined the recoverable amount of the renewables CGU by calculating its fair value less cost to sell using discounted cash flow projections. The Corporation's long-range forecasts, which represent forecasted cash flows for generating facilities over their expected useful lives, ranging from 8 to 58 years are the primary source of information for determining fair value. They contain forecasts for electricity production, sale, revenues, operating costs, and capital expenditures. In developing these plans, various assumptions, such as electricity prices, natural gas prices, and cost inflation rates are established by senior management. These assumptions take into account existing and forecast prices, regional supply-demand balances, other macroeconomic factors, and historical trends and variability. The results of the long-range forecasts are reviewed and approved by senior management.

The key assumptions impacting the determination of fair value for the renewables CGU are electricity production and sales prices. Forecasts of electricity production for each plant are determined taking into consideration contracts for the sale of electricity, historic production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each plant are determined by taking into consideration contract prices for plants subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the plant's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Discount rates ranging from 5.3 per cent to 7.7 per cent have been used for the renewables goodwill impairment calculation performed in 2011.

No reasonably possible change in the assumptions would result in any impairment of goodwill.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power contracts	Intangibles under development	Total
Cost					
As at Jan. 1, 2010	142	88	179	14	423
Additions	5	–	3	21	29
Retirements	–	(3)	–	–	(3)
Transfers	–	23	–	(21)	2
As at Dec. 31, 2010	147	108	182	14	451
Additions	5	2	–	23	30
Retirements	–	(2)	–	–	(2)
Transfers	–	19	–	(19)	–
As at Dec. 31, 2011	**152**	**127**	**182**	**18**	**479**
Accumulated amortization					
As at Jan. 1, 2010	88	41	1	–	130
Amortization	4	21	11	–	36
Retirements	–	(3)	–	–	(3)
As at Dec. 31, 2010	92	59	12	–	163
Amortization	4	22	9	–	35
Retirements	–	(2)	–	–	(2)
As at Dec. 31, 2011	**96**	**79**	**21**	**–**	**196**
Carrying amount					
As at Jan. 1, 2010	54	47	178	14	293
As at Dec. 31, 2010	55	49	170	14	288
As at Dec. 31, 2011	**56**	**48**	**161**	**18**	**283**

20. Other Assets

The components of other assets are as follows:

As at	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Deferred license fees	**22**	23	22
Project development costs	**36**	49	45
Deferred service costs	**18**	12	19
Keephills Unit 3 transmission deposit	**8**	8	8
Other	**6**	10	9
Total other assets	**90**	102	103

Deferred license fees consist primarily of licenses 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 licenses relate.

Project development costs include external, direct, and incremental costs incurred during the development phase of future power projects. The appropriateness of the carrying value of these costs is evaluated each reporting period, and unrecoverable amounts for projects no longer probable of occurring are charged to expense. In 2011, the Corporation wrote off $6 million of project development costs associated with the Saint-Valentin wind project.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 site. These costs are being amortized over the life of these projects.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next 10 years, as long as certain performance criteria are met.

21. Decomissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
Balance, Jan. 1, 2010	311	37	348
Liabilities incurred	2	7	9
Liabilities settled	(37)	(19)	(56)
Accretion	17	1	18
Transfer to liabilities held for sale	(3)	–	(3)
Revisions in estimated cash flows [1]	(21)	6	(15)
Revisions in discount rates	19	(1)	18
Reversals	–	(6)	(6)
Change in foreign exchange rates	(3)	–	(3)
Balance, Dec. 31, 2010	285	25	310
Liabilities incurred	20	67	87
Liabilities settled	(33)	(14)	(47)
Accretion	18	1	19
Disposals	(1)	(1)	(2)
Revisions in estimated cash flows	2	4	6
Revisions in discount rates	8	–	8
Reversals	–	(1)	(1)
Change in foreign exchange rates	2	–	2
Balance, Dec. 31, 2011	**301**	**81**	**382**

1 *Revisions in estimated cash flows for the decomissioning and restoration provision are primarily due to changes in the estimated costs associated with the decommissioning of the Wabamun plant, which was shut down on March 31, 2010.*

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2010	285	25	310
Current portion	38	16	54
Non-current portion	247	9	256
Balance, Dec. 31, 2011	**301**	**81**	**382**
Current portion	**26**	**73**	**99**
Non-current portion	**275**	**8**	**283**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.0 billion, which will be incurred between 2012 and 2072. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2011, the Corporation had provided a surety bond in the amount of U.S.$131 million (Dec. 31, 2010 – U.S.$192 million, Jan. 1, 2010 – U.S.$192 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2011, the Corporation had provided letters of credit in the amount of $69 million (Dec. 31, 2010 – $72 million, Jan. 1, 2010 – $67 million) in support of future decommissioning obligations at the Alberta mine.

B. Other Provisions

Other provisions include amounts related to an onerous natural gas transportation contract and provisions arising from ongoing business activities.

22. Long-Term Debt

A. Amounts Outstanding

As at	Dec. 31, 2011			Dec. 31, 2010			Jan. 1, 2010		
	Carrying value	**Face value**	**Interest [1]**	Carrying value	Face value	Interest [1]	Carrying value	Face value	Interest [1]
Credit facilities [2]	**806**	**806**	**2.1%**	645	645	1.4%	1,061	1,061	1.0%
Debentures	**833**	**851**	**6.6%**	1,058	1,076	6.7%	1,058	1,076	6.7%
Senior notes [3]	**1,979**	**1,940**	**6.0%**	1,931	1,902	6.0%	1,686	1,684	5.9%
Non-recourse	**375**	**382**	**5.9%**	374	383	5.9%	376	386	5.9%
Other	**44**	**44**	**6.6%**	52	52	6.7%	59	59	6.7%
	4,037	**4,023**		4,060	4,058		4,240	4,266	
Less: recourse current portion	**(314)**	**(314)**		(235)	(233)		(7)	(7)	
Less: non-recourse current portion	**(2)**	**(2)**		(2)	(2)		(2)	(2)	
Total long-term debt	**3,721**	**3,707**		3,823	3,823		4,231	4,257	

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 *U.S. face value at Dec. 31, 2011 – U.S.$1,900 million, Dec. 31, 2010 – U.S.$1,900 million, Jan. 1, 2010 – U.S.$1,600 million.*

A portion of the fixed rate components of the Corporation's debentures and senior notes have been hedged using fixed to floating interest rate swaps *(Note 14)* and are recorded at fair value. The balance of long-term debt is not hedged and is recorded at amortized 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 business. The facility is a four-year revolving credit facility that was last renewed in June 2011 and matures in 2015. 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. A total of U.S.$300 million of the credit facilities has been designated as a hedge of the Corporation's net investment in U.S. foreign operations. The Corporation also has $240 million available in committed bilateral credit facilities, all of which mature in 2013.

Debentures bear interest at fixed rates ranging from 6.4 per cent to 7.3 per cent and have maturity dates ranging from 2014 to 2030. During 2011, the Corporation's 6.9 per cent medium term notes matured and were paid out in the amount of $225 million.

Senior notes bear interest at rates ranging from 4.75 per cent to 6.75 per cent and have maturity dates ranging from 2012 to 2040. A total of U.S.$800 million of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations. During 2010, the Corporation issued senior notes in the amount of U.S. $300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040.

Non-recourse debt consists of debentures issued by Canadian Hydro that have maturity dates ranging from 2012 to 2018 and bear interest at rates ranging from 5.3 per cent to 10.9 per cent and includes $20 million of U.S. denominated debt.

Other consists of notes payable for the Windsor plant that bear interest at a fixed rate of 7.4 per cent and are recourse to the Corporation through a standby letter of credit. These mature in November 2014. Also included is a commercial loan obligation that 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.

TransAlta's debt contains terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2011, the Corporation was in compliance with all debt covenants.

B. Principal Repayments

2012	316
2013	622
2014	209
2015	1,167
2016	29
2017 and thereafter	1,680
Total [1]	**4,023**

1 *Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.*

C. Guarantees

Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and 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 Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2011 was $328 million (Dec. 31, 2010 – $297 million, Jan. 1, 2010 – $334 million) with no (Dec. 31, 2010 – nil, Jan. 1, 2010 – nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.0 billion (Dec. 31, 2010 – $2.0 billion, Jan. 1, 2010 – $2.1 billion) of committed credit facilities, of which $0.9 billion (Dec. 31, 2010 – $1.1 billion, Jan. 1 2010 – $0.7 billion) is not drawn, and is available as of Dec. 31, 2011, subject to customary borrowing conditions.

In addition to the $0.9 billion available under the credit facilities, TransAlta also has $49 million of cash available.

23. Deferred Credits and Other Long-Term Liabilities

The components of deferred credits and other long-term liabilities are as follows:

As at	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Deferred coal revenues	**66**	61	51
Long-term power contracts	**24**	28	32
Defined benefit obligation *(Note 28)*	**190**	161	138
Long-term incentive accruals	**18**	8	–
Other	**7**	11	15
Total deferred credits and other long-term liabilities	**305**	269	236

The long-term power contracts represent the fair value adjustments for various plants to deliver power at less than the prevailing market price at the time of the acquisition. The long-term power contracts are amortized on a straight-line basis over the life of the contract.

Deferred coal revenues consist of payments received from Keephills 3 Limited Partnership for future coal deliveries prior to the commercial operations of the Keephills Unit 3 facility. These amounts are being amortized into revenue over the life of the coal supply agreement since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

24. Common Shares

A. Issued and Outstanding

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

Year ended Dec. 31	2011		2010	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**220.3**	**2,204**	218.4	2,164
Issued under dividend reinvestment and share purchase plan	**3.2**	**67**	1.6	35
Issued under share-based payment plans *(Note 27)*	**0.1**	**2**	0.1	1
Issued under PSOP *(Note 27)*	**-**	**-**	0.2	4
Issued and outstanding, end of year	**223.6**	**2,273**	220.3	2,204

During 2010, no shares were acquired or cancelled under the Normal Course Issuer Bid program prior to its expiry on May 6, 2010.

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 29, 2010.

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 existing DRASP plan, eligible participants are able to purchase additional common shares by reinvesting dividends or making additional contributions. On February 21, 2012, the Corporation added a Premium Dividend™ Component to its existing DRASP Plan. The amended and restated plan is called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan"), and provides eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component). The discount on reinvested dividends can be adjusted to between zero to five per cent at the discretion of the Board of Directors. Participants will also be eligible to purchase new shares at a three per cent discount to the average market price under the optional cash payment component (the OCP Component) of the Plan by directly investing up to $5,000 per quarter. Eligiblie shareholders are not required to participate in the Plan. Those shareholders who have not elected or been deemed to have elected to participate in the Plan will continue to receive their quarterly cash dividends in the usual manner.

During the year ended Dec. 31, 2011, the Corporation issued 3.2 million common shares (2010 – 1.6 million) for $67 million (2010 – $35 million).

D. Earnings Per Share

Year ended Dec. 31	2011	2010
Net earnings attributable to common shareholders	**290**	255
Basic and diluted weighted average number of common shares outstanding	**222**	219
Net earnings per share attributable to common shareholders, basic and diluted	**1.31**	1.16

The effect of the stock options, PSOP and DRASP plan, does not materially affect the calculation of the total weighted average number of common shares outstanding *(Note 27)*.

E. Dividends

The following table summarizes the common share dividends declared in 2011 and 2010:

Date declared	Payment date	Dividend per share *($)*	Dividends payable as at Dec. 31, 2011	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Apr. 28, 2011	July 1, 2011	0.29	–	64	48	16
July 27, 2011	Oct. 1, 2011	0.29	–	65	48	17
Oct. 27, 2011	Jan. 1, 2012	0.29	66	65	45	20
Total		0.87	66	194		

Date declared	Payment date	Dividend per share *($)*	Dividends payable as at Dec. 31, 2010	Total dividends	Dividends paid in cash	Dividends paid in shares under DRASP
Jan. 29, 2010	April 1, 2010	0.29	–	63	60	3
April 1, 2010	July 1, 2010	0.29	–	64	49	15
July 22, 2010	Oct. 1, 2010	0.29	–	63	46	17
Oct. 28, 2010	Jan. 1, 2011	0.29	64	64	47	17
Dec. 7, 2010	April 1, 2011	0.29	65	65	48	17
Total		1.45	129	319		

25. Preferred Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares. The rights, privileges, restrictions and conditions attaching to such shares are determined by the Board of Directors, subject to certain limitations.

Year ended Dec. 31, 2011

	Number of shares *(millions)*	Amount	Dividend rate per share *($)*	Redemption price per share
Issued and outstanding, beginning of year	12	293	1.15	25
Issued [1]	11	269	1.15	25
Issued and outstanding, end of year	**23**	**562**		

1 *Net of after-tax issuance costs of $6 million ($8 million issuance costs, less tax-effects of $2 million).*

Year ended Dec. 31, 2010

	Number of shares *(millions)*	Amount	Dividend rate per share *($)*	Redemption price per share
Issued and outstanding, beginning of year	–	–	–	–
Issued [2]	12	293	1.15	25
Issued and outstanding, end of year	12	293		

2 *Net of after-tax issuance costs of $7 million ($9 million issuance costs, less tax-effects of $2 million).*

On Nov. 30, 2011, TransAlta completed a public offering of 11 million Series C Cumulative Redeemable Rate Reset First Preferred Shares under a prospectus supplement to the short form base shelf prospectus dated Nov. 15, 2011 for gross proceeds of $275 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.15 per share as approved by the Board of Directors, payable quarterly, yielding 4.60 per cent per annum, for the initial period ending June 30, 2017. The dividend rate will reset on June 30, 2017 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.10 per cent. The preferred shares are redeemable at the option of TransAlta on or after June 30, 2017 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends.

The Series C preferred shareholders will have the right at their option to convert their shares into Series D Cumulative Redeemable Rate Reset First Preferred Shares on June 30, 2017 and on June 30 of every fifth year thereafter. The holders of Series D preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 3.10 per cent.

On Dec. 10, 2010, TransAlta completed a public offering of 12 million Series A Cumulative Redeemable Rate Reset First Preferred Shares under a prospectus supplement to the short form base shelf prospectus dated Oct. 19, 2009 for gross proceeds of $300 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.15 per share as approved by the Board of Directors, payable quarterly, yielding 4.60 per cent per annum, for the initial period ending March 31, 2016. The dividend rate will reset on March 31, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 2.03 per cent. The preferred shares are redeemable at the option of TransAlta on or after March 31, 2016 and on March 31 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends. The first dividend was declared on Dec. 13, 2010.

The Series A preferred shareholders will have the right at their option to convert their shares into Series B Cumulative Redeemable Rate Reset First Preferred Shares on March 31, 2016 and on March 31 of every fifth year thereafter. The holders of Series B preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 2.03 per cent.

B. Dividends

The following table summarizes the preferred share dividends on the Series A Cumulative Redeemable Rate Reset First Preferred Shares, declared in 2011 and 2010:

Date declared	**Payment date**	**Dividend per share (*$*)**	**Dividends payable as at Dec. 31, 2011**	**Total dividends**
Apr. 28, 2011	June 30, 2011	0.2875	–	3
July 27, 2011	Sept. 30, 2011	0.2875	–	4
Oct. 27, 2011	Dec. 31, 2011	0.2875	–	4
Total		**0.8625**	**–**	**11**

Date declared	Payment date	Dividend per share (*$*)	Dividends payable as at Dec. 31, 2010	Total dividends
Dec. 13, 2010	March 31, 2011	0.3497	1	4
Total		0.3497	1	4

At Dec. 31, 2011, $1 million of dividends on the Series C Cumulative Redeemable Rate Reset First Preferred Shares were accrued. There were no dividends declared in 2011.

26. Accumulated Other Comprehensive (Loss) Income

The components of, and changes in, Accumulated other comprehensive (loss) income are as follows:

	2011	2010
Currency translation adjustment		
Balance, Jan. 1	**(27)**	-
Gains (losses) on translating net assets of foreign operations	**32**	(57)
(Losses) gains on financial instruments designated as hedges of foreign operations [1]	**(33)**	33
Reclassification of gains on translation of foreign operations to net earnings, net of tax [2]	**-**	(3)
Balance, Dec. 31	**(28)**	(27)
Cash flow hedges		
Balance, Jan. 1	**232**	189
(Losses) gains on derivatives designated as cash flow hedges, net of tax [3]	**(83)**	164
Reclassification of losses on derivatives designated as cash flow hedges to net earnings, net of tax [4]	**-**	8
Reclassification of gains on derivatives designated as cash flow hedges to non-financial assets, net of tax [5]	**(177)**	(129)
Balance, Dec. 31	**(28)**	232
Employee future benefits		
Balance, Jan. 1	**(20)**	-
Net actuarial losses on defined benefit plans, net of tax [6]	**(26)**	(20)
Balance, Dec. 31	**(46)**	(20)
Total AOCI	**(102)**	185

1 *Net of income tax recovery of 5 for the year ended Dec. 31, 2011 (2010 – 6 expense).*
2 *Net of income tax of nil for the year ended Dec. 31, 2011 (2010 – nil).*
3 *Net of income tax recovery of 7 for the year ended Dec. 31, 2011 (2010 – 87 expense).*
4 *Net of income tax of nil for the year ended Dec. 31, 2011 (2010 – 3 recovery).*
5 *Net of income tax expense of 94 for the year ended Dec. 31, 2011 (2010 – 65 expense).*
6 *Net of income tax recovery of 9 for the year ended Dec. 31, 2011 (2010 – 7 recovery).*

27. Share-Based Payment Plans

At Dec. 31, 2011, the Corporation had two types of share-based payment 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. Stock Option Plans

I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada 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 and is offered to all full-time and part-time employees in the U.S.

III. Australian Phantom Plan

This plan came into effect in 2001 and was offered to all full-time and part-time employees in Australia below the level of manager. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

IV. Total Plan Information

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2011 are outlined below:

	Options outstanding			Options exercisable	
Range of exercise prices *(per share)*	**Number outstanding at Dec. 31, 2011** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *(per share)*	**Number exercisable at Dec. 31, 2011** *(millions)*	**Weighted average exercise price** *(per share)*
11.13 - 17.18	0.1	2.2	14.55	0.1	14.55
17.19 - 23.23	1.0	6.6	21.33	0.4	20.20
23.24 - 29.28	–	–	–	–	-
29.29 - 35.32	0.6	6.1	32.12	0.5	32.12
11.13 - 35.32	**1.7**	**6.1**	**25.10**	**1.0**	**24.46**

The change in the number of options outstanding under the option plans is outlined below:

Year ended Dec. 31	**2011**		2010	
	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	**2.2**	**24.94**	1.5	26.36
Granted	**-**	**-**	0.9	22.27
Exercised	**-**	**-**	(0.1)	16.20
Forfeited	**(0.5)**	**25.35**	(0.1)	26.61
Outstanding, end of year	**1.7**	**25.10**	2.2	24.94

The Corporation uses the fair value method of accounting for awards granted under its stock option plans.

No stock options were granted in 2011. On Feb. 1, 2010, 0.9 million stock options were granted at a strike price of $22.46, 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.$20.75, 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 instalments over four years starting Feb. 1, 2011 and expire after 10 years. The estimated weighted average fair value of these options granted was determined using the Black-Scholes option-pricing model and the following weighted average assumptions, resulting in a weighted average fair value of $3.63 per option:

	2010
Risk-free interest rate *(%)*	2.4
Expected life of the options *(years)*	5.0
Dividend rate *(%)*	5.1
Volatility in the price of the corporation's shares *(%)*	29.4
Forfeiture rate *(%)*	9.6

The expected life of the option and volatility in the share price is based on historical data and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the option is indicative of future trends, which may also not necessarily be the actual outcome.

The expense recognized arising from equity-settled share-based payment transactions was $2 million (2010 – $2 million).

B. Performance Share Ownership Plan

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to award to employees and directors up to an aggregate of 4.0 million common shares. During 2010, the authorized amount was increased to 6.5 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, cannot 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, including the value of reinvested dividends over the period, or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. The ultimate awarding of PSOP in any year is at the discretion of TransAlta's Human Resource Committee ("HRC"). Once a participant's PSOP eligibility for an award has been established, 50 per cent of the shares may be released to the participant when the Board of Directors use share settlements on the awards, while the remaining 50 per cent will be held in trust for one additional year for employees below vice-president level, and for two additional years for employees at the vice-president level and above. If the awards are paid out in cash, they are paid immediately. 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. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued using the closing share price.

Year ended Dec. 31 *(millions)*	**2011**	2010
Number of grants outstanding, beginning of year	**1.7**	1.0
Granted	**1.4**	1.2
Awarded by HRC	**-**	(0.2)
Forfeited	**(0.2)**	(0.3)
Number of grants outstanding, end of year	**2.9**	1.7

In 2011, pre-tax PSOP compensation expense was $9 million (2010 – $7 million), which is included in OM&A expense in the Consolidated Statements of Earnings. In 2011, 50,560 common shares (2010 – 166,169 common shares) were issued at $21.15 per share (2010 – $23.48 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. An agent 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, 2011, accounts receivable from employees under the plan totalled $1 million (Dec. 31, 2010 – $2 million, Jan. 1, 2010 – $3 million).

28. 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 Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective December 31, 2010, resulting in no future benefits being earned.

The latest actuarial valuations for accounting purposes of the Canadian and U.S. pension plans was at Dec. 31, 2011 and Jan. 1, 2011, respectively. The measurement date used to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2011. The last actuarial valuation for funding purposes of the Canadian registered plan was Dec. 31, 2009, and the effective date of the next required valuation for funding purposes is Dec. 31, 2012. The last actuarial valuation for funding purposes of the U.S. pension plan was Jan 1, 2011 which is prepared and filed on an annual basis. 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 $63 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 and retired members (other post-employment benefits). The latest actuarial valuation of these Canadian and U.S. plans was as at Dec. 31, 2010 and Jan. 1, 2011, respectively. The measurement date used to determine the present value of the defined benefit obligation for both Plans was Dec. 31, 2011.

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, 2011	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**2**	**2**	**2**	**6**
Interest cost	**19**	**4**	**1**	**24**
Expected return on plan assets	**(21)**	**-**	**-**	**(21)**
Past service costs	**-**	**1**	**-**	**1**
Defined benefit expense	**-**	**7**	**3**	**10**
Defined contribution expense	**19**	**-**	**-**	**19**
Net expense	**19**	**7**	**3**	**29**

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Current service cost	2	2	2	6
Interest cost	21	4	2	27
Expected return on plan assets	(21)	-	-	(21)
Curtailment	(1)	-	(1)	(2)
Defined benefit expense	1	6	3	10
Defined contribution expense	19	-	-	19
Net expense	20	6	3	29

The amounts recognized in OCI during the year are as follows:

	Registered	**Supplemental**	**Other**	**Total**
Balance, Jan. 1, 2010	-	-	-	-
Actuarial (loss) gain	(23)	(8)	3	(28)
Balance, Dec. 31, 2010	(23)	(8)	3	(28)
Actuarial (loss)	(31)	(3)	(1)	(35)
Balance, Dec. 31, 2011	**(54)**	**(11)**	**2**	**(63)**

The history of experience adjustments is as follows:

Year ended Dec. 31, 2011	**Registered**	**Supplemental**	**Other**	**Total**
Experience adjustments on plan assets	**(10)**	**-**	**-**	**(10)**
Experience adjustments on plan liabilities	**(21)**	**(3)**	**(1)**	**(25)**

Year ended Dec. 31, 2010	Registered	Supplemental	Other	Total
Experience adjustments on plan assets	7	-	-	7
Experience adjustments on plan liabilities	(30)	(8)	3	(35)

C. Status of Plans

The status of the defined benefit and other health and dental benefit plans is as follows:

As at Dec. 31, 2011	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**294**	**5**	**–**	**299**
Present value of defined benefit obligation	**396**	**71**	**32**	**499**
Funded status – plan deficit	**(102)**	**(66)**	**(32)**	**(200)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(3)**	**(4)**	**(3)**	**(10)**
Other long-term liabilities	**(99)**	**(62)**	**(29)**	**(190)**
Total amount recognized	**(102)**	**(66)**	**(32)**	**(200)**

As at Dec. 31, 2010	Registered	Supplemental	Other	Total
Fair value of plan assets	304	4	–	308
Present value of defined benefit obligation	382	66	29	477
Funded status – plan deficit	(78)	(62)	(29)	(169)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	–	(5)	(3)	(8)
Other long-term liabilities	(78)	(57)	(26)	(161)
Total amount recognized	(78)	(62)	(29)	(169)

D. 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 as at Jan. 1, 2010	299	3	–	302
Expected return on plan assets	21	–	–	21
Contributions	5	4	3	12
Benefits paid	(26)	(3)	(3)	(32)
Effect of translation on U.S. plans	(2)	–	–	(2)
Actual return on plan assets [1]	7	–	–	7
Fair value of plan assets as at Dec. 31, 2010	304	4	–	308
Expected return on plan assets	21	–	–	21
Contributions	7	5	2	14
Benefits paid	(28)	(4)	(2)	(34)
Actual return on plan assets [1]	(10)	–	–	(10)
Fair value of plan assets as at Dec. 31, 2011	**294**	**5**	**–**	**299**

1 *Net of expenses.*

The allocation of defined benefit plan assets by major asset category at 2011 and 2010 is as follows:

Year ended Dec. 31, 2011 *(per cent)*	**Registered**	**Supplemental**
Equity securities	**49**	**–**
Debt securities	**49**	**–**
Money market investments	**1**	**–**
Cash and cash equivalents	**1**	**100**
Total	**100**	**100**

Year ended Dec. 31, 2010 *(per cent)*	Registered	Supplemental
Equity securities	51	–
Debt securities	46	–
Cash and cash equivalents	3	100
Total	100	100

Plan assets do not include any common shares of the Corporation at Dec. 31, 2011 and Dec. 31, 2010. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2011 (Dec. 31, 2010 – $0.1 million).

E. Defined Benefit Obligation

The present value of the defined benefit obligation for the defined benefit and other health and dental benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
Present value of defined benefit obligation as at Jan. 1, 2010	358	55	33	446
Current service cost	2	2	2	6
Interest cost	21	4	2	27
Benefits paid	(26)	(3)	(3)	(32)
Curtailment	(1)	–	(1)	(2)
Effect of translation on U.S. plans	(2)	–	(1)	(3)
Actuarial loss (gain)	30	8	(3)	35
Present value of defined benefit obligation as at Dec. 31, 2010	382	66	29	477
Current service cost	2	2	2	6
Past service cost	–	1	–	1
Interest cost	19	3	2	24
Benefits paid	(28)	(4)	(2)	(34)
Actuarial loss	21	3	1	25
Present value of defined benefit obligation as at Dec. 31, 2011	**396**	**71**	**32**	**499**

F. Contributions

The expected employer contributions on the defined benefit and other health and dental benefit plans are as follows:

	Registered	**Supplemental**	**Other**	**Total**
Expected employer contributions (2012)	3	4	3	10

G. Assumptions

The significant actuarial assumptions adopted in measuring the Corporation's defined benefit liability of the defined benefit and other health and dental benefit plans are as follows:

As at Dec. 31, 2011 *(per cent)*	Registered	Supplemental	Other
Defined benefit liability			
Discount rate	**4.8**	**4.8**	**4.8**
Rate of compensation increase	**3.0**	**3.0**	**-**
Expected rate of return on plan assets	**7.1**	**-**	**-**
Assumed health care cost trend rate			
Health care cost escalation	**-**	**-**	**8.3**[1]
Dental care cost escalation	**-**	**-**	**4.0**
Provincial health care premium escalation	**-**	**-**	**6.0**

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.*

As at Dec. 31, 2010 *(per cent)*	Registered	Supplemental	Other
Defined benefit liability			
Discount rate	5.2	5.3	5.0
Rate of compensation increase	3.0	3.0	-
Expected rate of return on plan assets	7.1	-	-
Assumed health care cost trend rate			
Health care cost escalation	-	-	8.7[2]
Dental care cost escalation	-	-	4.0
Provincial health care premium escalation	-	-	6.0

2 *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 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, health care cost trend rate, or expected rate of return on plan assets:

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2011	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% increase in the discount rate					
Impact on 2011 defined benefit obligation	(34)	(8)	(2)	(2)	(1)
Impact on 2012 estimated expense	1	-	-	-	-
1% decrease in the discount rate					
Impact on 2011 defined benefit obligation	41	11	2	3	1
Impact on 2012 estimated expense	(2)	-	-	-	-
1% increase in the health care cost trend rate					
Impact on 2011 defined benefit obligation	-	-	2	-	1
Impact on 2012 estimated expense	-	-	-	-	-
1% decrease in the health care cost trend rate					
Impact on 2011 defined benefit obligation	-	-	(2)	-	(1)
Impact on 2012 estimated expense	-	-	-	-	-
1% increase in the expected rate of return on plan assets					
Impact on 2012 estimated expense	(3)	-	-	-	-
1% decrease in the expected rate of return on plan assets					
Impact on 2012 estimated expense	3	-	-	-	-

29. Joint Ventures

Joint ventures at Dec. 31, 2011 included the following:

Jointly controlled assets	Ownership *(per cent)*	Description
Sheerness	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Fort Saskatchewan	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
McBride Lake	50	Wind generation facilities in Alberta operated by TransAlta
Goldfields Power	50	Gas-fired plant in Australia operated by TransAlta
Genesee Unit 3	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	50	Coal-fired plant operated by TransAlta
Soderglen	50	Wind generation facilities in Alberta operated by TransAlta
Pingston	50	Hydro facility in British Columbia operated by TransAlta
Project Pioneer	25	Prototype carbon capture and storage facility under construction to be operated by TransAlta

Jointly controlled entities	Ownership *(per cent)*	Description
CE Gen	50	Geothermal and gas plants in the United States operated by CE Gen affiliates
Wailuku	50	A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company

30. Changes in Non-Cash Operating Working Capital

Year ended Dec. 31	2011	2010
(Use) source:		
Accounts receivable	**(130)**	(7)
Prepaid expenses	**3**	6
Income taxes receivable	**13**	17
Inventory	**(27)**	31
Accounts payable and accrued liabilities	**(16)**	1
Provisions	**35**	(13)
Income taxes payable	**7**	(2)
Change in non-cash operating working capital	**(115)**	33

31. Capital

TransAlta's capital is comprised of the following:

As at	Dec. 31, 2011	Dec. 31, 2010	Increase/ (decrease)
Current portion of long-term debt	**316**	237	79
Less: cash and cash equivalents	**(49)**	(35)	(14)
	267	202	65
Long-term debt	**3,721**	3,823	(102)
Equity			
Non-controlling interests	**358**	431	(73)
Preferred shares	**562**	293	269
Common shares	**2,273**	2,204	69
Contributed surplus	**9**	7	2
Retained earnings	**527**	431	96
Accumulated other comprehensive (loss) income	**(102)**	185	(287)
	7,348	7,374	(26)
Total capital	**7,615**	7,576	39

Total capital remains largely unchanged from the beginning of the year. Changes in the balances of the components of capital are as follows:

Long-term debt (including current portion) decreased primarily due to the payout on the maturity of the medium term notes; a net increase in amounts outstanding under credit facilities; and unfavourable foreign exchange movements *(Note 22)*.

Preferred shares increased in 2011 are a result of the issuance of 11 million Series C Preferred Shares for net proceeds of $269 million *(Note 25)*.

AOCI decreased in 2011 primarily due to the recognition of unrealized losses on derivatives designated as hedging instruments and higher reclassifications to net earnings of unrealized gains related to ineffective hedging relationships.

TransAlta's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2010, and are as follows:

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 credit 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 seeks to manage the Corporation's capital in line with the following targets:

Cash flow to interest coverage is calculated as cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest income. The Corporation's goal is to maintain this ratio in a range of four to five times.

Cash flow to debt is calculated as cash flow from operating activities before changes in working capital divided by average total debt. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Debt to invested capital is calculated as debt less cash and cash equivalents divided by debt, non-controlling interests, and shareholders' equity less cash and cash equivalents. The Corporation's goal is to maintain this ratio in a range of 55 to 60 per cent.

These ratios are outlined below:

	Dec. 31, 2011	Dec. 31, 2010	**Target**
Cash flow to interest coverage *(times)* [1]	**4.4**	4.6	Minimum of 4
Cash flow to debt *(%)* [1]	**20.2**	19.6	Minimum of 25
Debt to invested capital *(%)*	**52.4**	53.1	Maximum of 55

1 *Last 12 months.*

Cash flow to interest coverage decreased in 2011 compared to 2010 primarily due to lower capitalized interest. Cash flow to debt improved in 2011 compared to 2010 due to lower average debt levels in 2011. Debt to invested capital decreased as at Dec. 31, 2011 compared to 2010 due to lower debt levels and higher net earnings.

TransAlta routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and capital asset expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Capital Assets

For the year ended Dec. 31, 2011, net cash outflows, after cash dividends and capital asset additions, are summarized below:

Year ended Dec. 31	**2011**	2010	**(Decrease) increase in cash flows**
Cash flow from operating activities	**694**	838	(144)
Dividends paid on common shares	**(191)**	(216)	25
Capital asset expenditures	**(453)**	(808)	355
Net cash outflow (inflow)	**50**	(186)	236

The increase in total net cash flows primarily resulted from lower capital asset expenditures and lower common share dividends paid in cash as a result of the DRASP plan.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2011, $0.9 billion of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta opportunistically accesses the capital market to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

During 2011, the Corporation issued 3.3 million common shares for total net proceeds of $69 million. The Corporation also issued 11.0 million Series C Preferred Shares for total net proceeds of $269 million.

During 2010, the Corporation issued 1.9 million common shares for total net proceeds of $40 million. The Corporation also issued 12.0 million Preferred Shares for total net proceeds of $293 million.

Dividends on the Corporation's common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers the Corporation's financial performance, its results of operations, cash flow and needs with respect to financing ongoing operations and growth, balanced against returning capital to shareholders.

32. Prior Period Regulatory Decision

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$47 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator and the California Department of Water Resources during the 2000-2001 period. In addition, the California parties have sought additional refunds which to date have been rejected by FERC. TransAlta does not believe the California parties will be successful in obtaining additional refunds and is pursuing cost offsets to the refunds awarded by FERC. TransAlta established a U.S.$47 million provision to cover any potential refunds and continues to seek relief from this obligation. A final ruling is not expected in the near future.

33. Related Party Transactions

Details of the Corporation's principal operating subsidiaries are as follows:

Subsidiary	Country	Ownership *(per cent)*	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy trading
TransAlta Energy Marketing (U.S.) Inc.	U.S.	100	Energy trading
TransAlta Energy (Australia) Pty Ltd.	Australia	100	Generation and sale of electricity
Canadian Hydro Developers, Inc.	Canada	100	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO, the Chief Officers reporting directly to the President and CEO, and the Board of Directors. Key management personnel compensation is as follows:

Year ended Dec. 31	**2011**	2010
Total compensation	**12**	11
Comprised of:		
Short-term employee benefits	**6**	7
Post-employment benefits	**1**	1
Other long-term benefits	**1**	1
Share-based payment	**4**	2

34. Commitments

In addition to the commitments disclosed in the previous notes, 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, long-term service agreements, interest on long-term debt, and growth project commitments are as follows:

	Fixed price gas purchase and transportation contracts	Transmission	Coal supply and mining agreements	Long-term service agreements	Growth project commitments	Total
2012	78	6	54	18	220	376
2013	45	8	54	17	–	124
2014	43	8	54	17	–	122
2015	22	8	54	17	–	101
2016	20	8	59	9	–	96
2017 and thereafter	484	5	291	3	–	783
Total	**692**	**43**	**566**	**81**	**220**	**1,602**

A. Fixed Price Gas Purchase and Transportation Contracts

Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place.

B. Transmission

TransAlta has several agreements to purchase 400 MW of Pacific Northwest transmission network capacity. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Centralia Thermal has various coal supply and associated rail transport contracts to provide coal for use in production. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2012.

At Alberta Thermal, the mine is operated by a third party who is paid a base fixed fee, adjusted by an incentive or penalty based on actual versus budgeted volumes and costs, to supply coal for the Corporation's plants. The contract expires Dec. 31, 2020.

D. 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.

E. Growth Project Commitments

On Sept. 13, 2010, TransAlta obtained approval from the Board of Directors for a 15 MW efficiency uprate at Unit 3 of its Sundance facility. The total capital cost of the project is estimated to be $27 million with commercial operations expected to begin during the fourth quarter of 2012. As at Dec. 31, 2011, the total capital incurred on this project was $11 million.

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 406 MW, and are expected to be operational by the end of 2012. The capital cost of the projects is estimated at $51 million. As at Dec. 31, 2011, the total capital incurred on these projects was $23 million.

On March 28, 2011, the Corporation announced it had received approval from the Government of Quebec to proceed with the construction of the 68 MW New Richmond wind project located on the Gaspé Peninsula. New Richmond is contracted under a 20-year Electricity Supply Agreement with Hydro-Québec Distribution. The cost of the project is estimated to be approximately $205 million and commercial operations are expected to commence during the fourth quarter of 2012. As at Dec. 31, 2011, the total capital incurred on the project was $29 million.

Growth project commitments are as follows:

	Sundance Unit 3 uprate	Keephills Unit 1 uprate	Keephills Unit 2 uprate	New Richmond	Total
2012	16	12	16	176	220
2013	–	–	–	–	–
2014	–	–	–	–	–
2015	–	–	–	–	–
2016	–	–	–	–	–
2017 and thereafter	–	–	–	–	–
Total	**16**	**12**	**16**	**176**	**220**

F. TransAlta Energy Bill Commitments

As part of the Bill and MoA signed into law in the State of Washington, the Corporation has committed to fund $55 million over the life of the Centralia coal plant to support economic development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. In the event that legislation changes, this payment will no longer be required.

G. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts include: electricity and thermal capacity, availability and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

35. Contingencies

TransAlta is occasionally named as a party in various claims and legal proceedings that 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. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta.

36. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three reportable segments as described in Note 1.

Each segment assumes responsibility for its operating results.

Generation expenses include Energy Trading's intersegment charge for energy marketing. Energy Trading's operating expenses are presented net of these intersegment charges. Due to the transition to IFRS, the Corporation's interest in the Fort Saskatchewan generating facility is now accounted for as a finance lease and the Corporation's interests in the CE Gen and Wailuku joint ventures are now accounted for using the equity method. Although these assets no longer contribute to the operating income of the Generation Segment for accounting purposes, it is management's view that these facilities still form a part of the Corporation's Generation Segment and are included in the Generation Segment below.

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, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	2,526	137	-	2,663
Fuel and purchased power *(Note 5)*	947	-	-	947
	1,579	137	-	1,716
Operations, maintenance, and administration *(Note 5)*	419	43	83	545
Depreciation and amortization	460	1	21	482
Taxes, other than income taxes	27	-	-	27
Intersegment cost allocation	8	(8)	-	-
	914	36	104	1,054
	665	101	(104)	662
Finance lease income *(Note 6)*	8	-	-	8
Equity income *(Note 7)*	14	-	-	14
Gain on sale of assets *(Note 4)*	16	-	-	16
Asset impairment charges *(Note 8)*	(17)	-	-	(17)
Reserve on collateral *(Note 14 and 16)*	-	(18)	-	(18)
Other income				2
Foreign exchange loss				(3)
Net interest expense *(Notes 9 and 14)*				(215)
Earnings before income taxes				449

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Revenues	2,632	41	-	2,673
Fuel and purchased power *(Note 5)*	1,185	-	-	1,185
	1,447	41	-	1,488
Operations, maintenance, and administration *(Note 5)*	424	17	69	510
Depreciation and amortization	443	2	19	464
Taxes, other than income taxes	27	-	-	27
Intersegment cost allocation	5	(5)	-	-
	899	14	88	1,001
	548	27	(88)	487
Finance lease income *(Note 6)*	8	-	-	8
Equity income *(Note 7)*	7	-	-	7
Asset impairment charges *(Note 8)*	(28)	-	-	(28)
Foreign exchange gain				8
Net interest expense *(Notes 9 and 14)*				(178)
Earnings before income taxes				304

Included in the Generation Segment results is $24 million (2010 – $18 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2011	**Generation** [1]	**Energy Trading**	**Corporate**	**Total**
Goodwill *(Note 18)*	**417**	**30**	**–**	**447**
Total segment assets	**9,007**	**394**	**359**	**9,760**

1 *Total Generation Segment assets includes $193 million related to investments in joint ventures accounted for using the equity method.*

As at Dec. 31, 2010	Generation [1]	Energy Trading	Corporate	Total
Goodwill *(Note 18)*	417	30	–	447
Total segment assets	9,166	132	337	9,635

1 *Total Generation Segment assets includes $190 million related to investments in joint ventures accounted for using the equity method.*

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2011	**Generation**	**Energy Trading**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment *(Note 17)*	**445**	**–**	**8**	**453**
Intangible assets *(Note 19)*	**7**	**1**	**22**	**30**

Year ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment *(Note 17)*	803	–	5	808
Intangible assets *(Note 19)*	11	2	16	29

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	**2011**	2010
Depreciation and amortization expense on the Consolidated Statements of Earnings	**482**	464
Depreciation included in fuel and purchased power	**40**	37
Other	**10**	10
Depreciation and amortization on the Consolidated Statements of Cash Flows	**532**	511

C. Geographic Information

I. Revenues

Year ended Dec. 31	**2011**	2010
Canada	**1,871**	1,754
U.S.	**674**	815
Australia	**118**	104
Total revenue	**2,663**	2,673

II. Non-Current Assets

	Property, plant, and equipment		**Intangible assets**		**Other assets**		**Goodwill**	
As at Dec. 31	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Canada	**6,299**	6,310	**275**	279	**52**	75	**417**	417
U.S.	**831**	814	**4**	5	**35**	25	**30**	30
Australia	**158**	170	**4**	4	**3**	2	**–**	–
Total	**7,288**	7,294	**283**	288	**90**	102	**447**	447

eleven-year financial and statistical summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2011	2010	2009
Financial Summary			
Statement of Earnings			
Revenues	**2,663**	2,673	2,770
Operating income	**662**	487	378
Net earnings attributable to common shareholders	**290**	255	181
Statement of Financial Position			
Total assets	**9,760**	9,635	9,762
Current portion of long-term debt, net of cash and cash equivalents	**267**	202	(51)
Long-term debt	**3,721**	3,823	4,411
Other non-controlling interests	**358**	431	478
Preferred securities	**-**	-	-
Equity attributable to shareholders	**3,269**	3,120	2,929
Total invested capital	**7,615**	7,576	7,767
Cash Flows			
Cash flow from operating activities	**694**	838	580
Cash flow used in investing activities	**(615)**	(765)	(1,598)
Common Share Information *(per share)*			
Net earnings	**1.31**	1.16	0.90
Comparable earnings [3]	**1.04**	0.97	0.90
Dividends paid on common shares	**1.16**	1.16	1.16
Book value *(at year-end)*	**12.08**	12.85	13.41
Market price:			
High	**23.24**	23.98	25.30
Low	**19.45**	19.61	18.11
Close *(Toronto Stock Exchange at Dec. 31)*	**21.02**	21.15	23.48
Ratios *(percentage except where noted)*			
Debt to invested capital	**52.4**	53.1	56.1
Debt to invested capital excluding non-recourse debt	**49.9**	50.7	52.6
Return on equity attributable to common shareholders	**10.6**	9.6	6.9
Comparable return on equity attributable to common shareholders [3]	**8.4**	8.0	6.9
Return on capital employed	**8.8**	6.6	5.7
Comparable return on capital employed [3]	**7.5**	6.3	5.8
Price/earnings ratio	**20.4**	21.8	26.1
Earnings coverage *(times)*	**2.7**	2.2	1.9
Dividend payout ratio based on net earnings	**66.9**	125.1	129.8
Dividend payout ratio based on comparable earnings [3]	**84.3**	149.8	129.8
Dividend payout ratio based on funds from operations [3]	**24.0**	39.6	-
Comparable EBITDA *(in millions of Canadian dollars)* [3]	**1,077**	955	888
Dividend coverage *(times)*	**3.6**	4.0	2.6
Dividend yield	**5.5**	5.5	4.9
Cash flow to debt	**20.2**	19.6	20.5
Cash flow to interest coverage *(times)*	**4.4**	4.6	4.9
Weighted average common shares for the year *(in millions)*	**222**	219	201
Common shares outstanding at Dec. 31 *(in millions)*	**224**	220	218
Statistical Summary			
Number of employees	**2,235**	2,389	2,343
Generating Capacity *(net MW)* [4]			
Coal	**4,325**	4,688	4,967
Gas	**1,532**	1,613	1,843
Renewables	**1,974**	1,950	1,965
Finance lease	**390**	390	-
Equity investments	**35**	35	-
Total generating capacity	**8,256**	8,676	8,775
Total generation production *(GWh)* [5]	**41,012**	48,614	45,736

Financial data presented for 2011 and 2010 is based on IFRS. Financial data for 2009 and prior is based on Canadian GAAP. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

1 *2002 and 2001 Energy Trading real-time contract revenues are restated to be presented on a gross basis.*
2 *Includes discontinued operations.*
3 *These ratios were calculated using non-IFRS measures. Periods for which the non-IFRS measure was not previously disclosed have not been calculated.*
4 *Represents TransAlta's ownership.*
5 *Includes discontinued operations.*

Ratio Formulas

Debt to invested capital = (debt – cash and cash equivalents)/(debt + non-controlling interests + total equity – cash and cash equivalents)

Return on common shareholders' equity = net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis/average equity attributable to common shareholders excluding Accumulated Other Comprehensive Income ("AOCI")

Earnings coverage = (net earnings attributable to common shareholders + income taxes + net interest expense)/(interest on debt – interest income)

2008	2007	2006	2005	2004	2003	2002	2001
3,110	2,775	2,677	2,664	2,838	2,509	1,815 [1]	2,560 [1]
533	541	157	421	478	554	224 [2]	469 [2]
235	309	45	199	170	234	190	215
7,815	7,157	7,460	7,741	8,133	8,420	7,420	7,878
194	600	296	(66)	(103)	(35)	146	475
2,564	1,837	2,221	2,605	3,058	3,162	2,707	2,511
469	496	535	559	616	478	263	281
–	–	175	175	175	451	452	453
2,510	2,299	2,428	2,543	2,473	2,460	2,040	1,990
5,737	5,232	5,655	5,756	6,061	6,516	5,608	5,710
1,038	847	490	619	613	757	438	716
(581)	(410)	(261)	(242)	(65)	(535)	(36)	(1,077)
1.18	1.53	0.22	1.01	0.88	1.26	1.12	1.27
1.46	1.31	1.16	0.88	0.70	0.69	0.99	–
1.08	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12.70	11.39	11.99	12.80	12.74	12.90	12.01	11.82
37.50	34.00	26.91	26.66	18.75	19.55	23.95	30.13
21.00	23.79	20.22	17.67	15.25	15.36	16.69	19.15
24.30	33.35	26.64	25.41	18.05	18.53	17.11	21.60
48.1	46.8	44.5	43.9	47.4	47.9	50.9	52.3
45.6	44.0	41.0	39.9	42.5	42.9	–	–
9.4	13.1	1.8	7.0	6.5	10.3	3.5	10.9
11.6	10.5	9.2	6.8	5.1	5.6	8.2	–
7.7	9.8	2.4	7.1	7.5	9.1	4.0	8.7
9.6	9.7	9.0	7.4	–	–	–	–
20.6	21.8	121.1	26.7	21.7	14.7	41.7	17.3
2.8	3.3	0.5	2.3	1.9	2.0	1.9	3.0
91.5	65.6	447.7	113.0	120.0	79.0	241.8	78.5
74.1	76.4	86.0	113.3	150.4	143.7	100.6	–
–	–	–	–	–	–	–	–
1,006	980	–	–	–	–	–	–
4.8	4.2	2.4	3.1	3.2	4.1	2.6	4.3
4.4	3.0	3.8	3.9	5.5	5.4	5.8	4.6
31.7	30.7	26.2	23.0	18.5	17.9	16.1	21.8
7.2	6.6	5.5	4.7	4.1	3.3	3.8	5.5
199	202	201	197	193	185	170	169
198	201	202	199	194	191	170	168
2,200	2,201	2,687	2,657	2,505	2,563	2,573	2,656
4,942	4,942	4,887	4,885	4,778	4,777	4,966	5,090
1,913	1,960	1,953	1,933	2,444	2,499	1,333	1,108
1,218	1,122	1,122	1,117	1,115	1,046	845	800
–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–
8,073	8,024	7,962	7,935	8,337	8,322	7,144	6,998
48,891	50,395	48,213	51,810	54,560	53,134	46,877	44,136

Return on capital employed = (earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense)/average annual invested capital excluding AOCI

Dividend yield = dividend per common share/current year's close price

Dividend payout ratio = common share dividends/net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis

Price/earnings ratio = current year's close price/basic earnings per share from continuing operations

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + net interest expense)/(interest on debt – interest income)

Dividend coverage = cash flow from operating activities/cash dividends paid on common shares

Cash flow to debt = cash flow from operating activities before changes in working capital/(two-year average of total debt – average cash and cash equivalents)

Comparable EBITDA = operating income + accretion of provisions per the Consolidated Statements of Cash Flows + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

shareholder information

Annual Meeting

The Annual meeting will be held at 11:00 a.m. MDT on Thursday, April 26, 2012, at the Metropolitan Conference Centre, 333 Fourth Avenue S.W., Calgary, Alberta.

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Exchanges

Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols

TransAlta Corporation common shares
TSX: TA, NYSE: TAC

TransAlta Corporation preferred securities
TSX: TA.Pr.D, TA.Pr.F

* *On November 1, 2010, CIBC Mellon Trust Company sold its issuer services business to Canadian Stock Transfer Company Inc. ("CST"). CST and American Stock Transfer & Trust Company, LLC (AST) form the North American division of the Link Group, an international network of providers of transfer agent and employee plan services. With offices in Toronto, Montreal, Calgary, Halifax and Vancouver, CST provides global solutions through local access points.*

Special Services for Registered Shareholders

Service	Description
Premium Dividend™ Dividend Reinvestment and Optional Common Share Purchase Plan[1]	Conveniently reinvest your TransAlta dividends and purchase common shares without brokerage costs or, as provided under the plan, obtain a cash return equivalent to 102 per cent of your dividend under the Premium Dividend™ component of the plan
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

To use these services please contact our transfer agent.

1 *Also available to non-registered shareholders.*

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split[2]
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares[3] 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.

2 *The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988 share split.*

3 *TransAlta Utilities Corporation became a wholly-owned subsidiary of TransAlta Corporation as a result of this reorganization.*

Dividend Declaration for Common Shares

Dividends are paid quarterly as determined by the Board. In determining the level of the dividend, the Board assesses the dividend payout as a percentage of earnings and as a percentage of cash flow from operations over a period of time. Dividends are at the discretion of the Board. In determining the dividend, the Board considers the Corporation's financial performance, its results of operations, cash flow and needs with respect to financing ongoing operations and growth balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

Common Share Dividends Declared

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2011	March 1, 2011	Feb. 25, 2011	$0.29
July 1, 2011	June 1, 2011	May 26, 2011 TAC[4]	$0.29
July 1, 2011	June 1, 2011	May 30, 2011 TA[4]	$0.29
Oct. 1, 2011	Sept. 1, 2011	Aug. 30, 2011	$0.29
Jan. 1, 2012	Dec. 1, 2011	Nov. 29, 2011	$0.29
April 1, 2012	March 1, 2012	Feb. 28, 2012	$0.29

Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

4 *The dividend payment has two Ex-Dividend dates due to the American Memorial Day holiday. The Toronto Stock Exchange (TA) Ex-Dividend date is May 30, 2011. The New York Stock Exchange (TAC) Ex-Dividend date is May 26, 2011.*

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Dec. 10, 2010 to but excluding March 31, 2016.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Nov. 30, 2011 to but excluding June 30, 2017.

Preferred Share Dividends Declared

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2011	March 1, 2011	Feb. 25, 2011	$0.3497[1]
June 30, 2011	June 1, 2011	May 30, 2011	$0.2875
Sept. 30, 2011	Sept. 1, 2011	Aug. 30, 2011	$0.2875
Dec. 31, 2011	Dec. 1, 2011	Nov. 29, 2011	$0.2875
March 31, 2012	March 1, 2012	Feb. 28, 2012	$0.2875

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2012	March 1, 2012	Feb. 28, 2012	$0.3844[2]

Dividends are paid on the last day of the month in March, June, September, and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

1 *The first quarterly dividend payable is based on a longer period, starting from the issue date of December 10, 2010 to March 31, 2011.*

2 *The first quarterly dividend payable is based on a longer period, starting from the issue date of Nov. 30, 2011 to March 31, 2012.*

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Vice-President & Corporate Secretary of the Corporation.

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:

Investor Relations
TransAlta Corporation
P.O. Box 1900, Station "M"
110 - 12th Avenue S.W.
Calgary, Alberta T2P 2M1

Phone
North America
1.800.387.3598 toll-free

Calgary/outside North America
403.267.2520

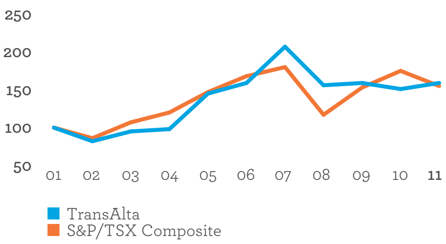
E-mail
investor_relations@transalta.com

Fax
403.267.2590

Website
www.transalta.com

shareholder highlights

Total Shareholder Return vs. S&P/TSX Composite Total Return Index
Year ended Dec. 31 (*$*)



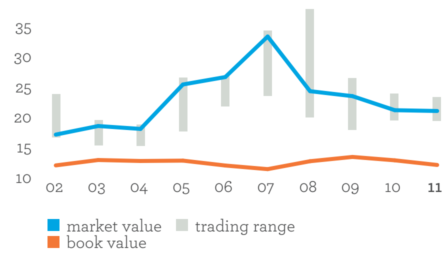
Total Shareholder Return vs. S&P/TSX Composite Total Return Index

	01	02	03	04	05	06	07	08	09	10	**11**
TransAlta	100	82	95	98	145	159	207	156	159	151	**159**
S&P/TSX Composite	100	86	107	120	147	168	180	117	153	175	**155**

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2001 would be worth today, assuming the reinvestment of dividends.

Source: Thomson Financial

Ten-year Trading Range & Market Value vs. Book Value[1]
(*$ per share*)



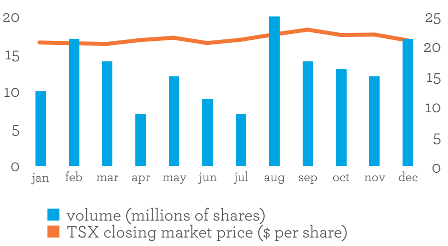
Ten-year Trading Range and Market Value vs. Book Value[1] ($ per share)

	02	03	04	05	06	07	08	09	10	**11**
Market value	17.11	18.53	18.05	25.41	26.64	33.35	24.30	23.48	21.15	**21.02**
Book value	12.01	12.90	12.74	12.80	11.99	11.39	12.70	13.41	12.85	**12.08**

1 *Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).*

Source: Thomson Financial and TransAlta (MD&A)

Monthly Volume and Market Price
(2011)

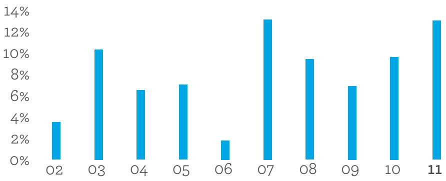


Monthly Volume and Market Price on Last Day of the Month

	jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec
Volume	10	17	14	7	12	9	7	20	14	13	12	17
TSX closing market price	20.68	20.55	20.44	21.08	21.47	20.59	21.13	22.02	22.81	21.93	21.99	21.02

Source: Thomson Financial

Return on Common Shareholders' Equity[2]
(*%*)



Return on Common Shareholders' Equity[2]

	02	03	04	05	06	07	08	09	10	**11**
ROE	3.5	10.3	6.5	7.0	1.8	13.1	9.4	6.9	9.6	**10.6**

2 *Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).*

Source: TransAlta (MD&A)

corporate information

TransAlta Corporate Officers

Dawn Farrell
President and Chief Executive Officer

Paul Taylor
President, U.S. Operations

Ken Stickland
Chief Legal and Business Development Officer

Brett Gellner
Chief Financial Officer

Dawn de Lima
Chief Human Resources Officer and
Executive Vice-President, Communications

Rob Schaefer
Executive Vice-President, Corporate Development

Cynthia Johnston
Executive Vice-President, Corporate Services

Hugo Shaw
Executive Vice-President, Operations

Robert (Bob) Emmott
Chief Engineer

William D.A. Bridge
Executive Vice-President, Business Development

David J. Koch
Vice-President, Controller

Maryse St.-Laurent
Vice-President and Corporate Secretary

Todd Stack
Treasurer

Corporate Governance – New York Stock Exchange Disclosure Differences

TransAlta's General Governance Guidelines/Board Charter, Committee Charters, position descriptions for the Chair, Committee Chair, President & CEO and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards. Currently there are no differences between our governance practices and those of the New York Stock Exchange.

Ethics Help-Line

The Audit and Risk Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number, fax line and e-mail address for employees, contractors, shareholders and other stakeholders to call with respect to accounting irregularities, ethical violations, or any other matters they wish to bring to the attention of the Board.

Ethics Help-Line number: **1.888.806.6646**
Fax: **403.267.7985**
E-mail: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**

glossary

Air Emissions: Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury, and greenhouse gases.

Alberta Power Purchase Arrangement (PPA): A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Availability: A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler: A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Brownfield Asset: A previously constructed electric power generating facility.

Btu (British Thermal Unit): A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

Capacity: The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Carbon Capture and Storage (CCS): An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

CO_2 Emissions Intensity: Amount of carbon dioxide emitted per MWh produced.

Coal Gasification: The conversion of solid fuel to gaseous form, for subsequent conversion into power, synthetic gas, hydrogen, or a variety of other chemical products.

Cogeneration: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate: To lower the rated electrical capability of a power generating facility or unit.

Expected Capability: Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

Flue Gas Desulphurization Unit (Scrubber): Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure: Literally means “major force”. These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigajoule (GJ): A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW): A measure of electric power equal to 1,000 megawatts.

Gigawatt Hour (GWh): A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenfield Asset: A new electric power generating facility built from the ground up on a new site.

Greenhouse Gas (GHG): Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Heat Rate: A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW): A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh): A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant Assets: TransAlta uses the term merchant to describe assets that have contracts with terms less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short and medium-term contracts.

Net Maximum Capacity: The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Peaker Plant: A plant usually housing low-efficiency steam units, gas turbines, diesels, or pumped-storage hydroelectric equipment normally used during peak load periods.

Renewable Power: Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Reserve Margin: An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Run Rate: The result of extrapolating financial data collected from a period of time less than one year to a full year.

Spark Spread: A measure of gross margin per MW (sales price less cost of natural gas).

Supercritical Technology: The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Target Zero: TransAlta's initiative designed to drive health, safety and environmental performance to zero lost-time, medical aid, and environmental incidents.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround: Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage: The shutdown of a generating unit due to an unanticipated breakdown.

Uprate: To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR): A measure to manage earnings exposure from energy trading activities.

In an effort to be environmentally responsible, please notify your financial institution to avoid duplicate mailings of this annual report.

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