TransAlta Corporation

Consolidated Financial Statements

December 31, 2014

Consolidated Financial Statements

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 (the "Board") 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 L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

February 18, 2015

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") 2013 framework to evaluate the effectiveness of TransAlta Corporation's internal control over financial reporting. Management believes that the COSO 2013 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 operations in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements 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 these joint arrangements. The 2014 consolidated financial statements of TransAlta Corporation included $678 million and $643 million of total and net assets, respectively, as of December 31, 2014, and $215 million and $73 million of revenues and net earnings, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta Corporation's internal control over financial reporting, as at December 31, 2014, 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, 2014, 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 L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

February 18, 2015

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). TransAlta 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 and Genesee Unit 3 joint arrangements, which are included in the 2014 consolidated financial statements of the Corporation and constituted $678 million and $643 million of total and net assets, respectively, as of December 31, 2014, and $215 million and $73 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 and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position as at December 31, 2014 and 2013, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2014 of TransAlta Corporation and our report dated February 18, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 18, 2015

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, 2014 and 2013, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the years in the three-year period ended December 31, 2014, 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 as issued by the International Accounting Standards Board, 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 auditors consider 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, 2014 and 2013, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

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, 2014, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 18, 2015 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 18, 2015

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2014**	2013 (Restated)*	2012 (Restated)*
Revenues *(Note 35)*	**2,623**	2,292	2,210
Fuel and purchased power *(Note 5)*	**1,092**	948	797
Gross margin	**1,531**	1,344	1,413
Operations, maintenance, and administration *(Note 5)*	**542**	516	499
Depreciation and amortization	**538**	525	509
Asset impairment charges (reversals) *(Note 6)*	**(6)**	(18)	324
Restructuring provision *(Note 21)*	**-**	(3)	13
Taxes, other than income taxes	**29**	27	28
Net other operating (income) losses *(Note 8)*	**(14)**	102	254
Operating income (loss)	**442**	195	(214)
Finance lease income *(Note 7)*	**49**	46	16
Equity loss *(Note 16)*	**-**	(10)	(15)
Net interest expense *(Note 9)*	**(254)**	(256)	(242)
Foreign exchange gain (loss)	**-**	1	(9)
Gain on sale of assets *(Note 4)*	**2**	12	3
Gain on sale of collateral *(Note 14)*	**-**	-	15
Other income	**-**	-	1
Earnings (loss) before income taxes	**239**	(12)	(445)
Income tax expense (recovery) *(Note 10)*	**7**	(8)	102
Net earnings (loss)	**232**	(4)	(547)
Net earnings (loss) attributable to:			
TransAlta shareholders	**182**	(33)	(584)
Non-controlling interests *(Note 11)*	**50**	29	37
	232	(4)	(547)
Net earnings (loss) attributable to TransAlta shareholders	**182**	(33)	(584)
Preferred share dividends *(Note 25)*	**41**	38	31
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Weighted average number of common shares outstanding in the year *(millions)*	**273**	264	235

Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 24)*	**0.52**	(0.27)	(2.62)

* *See Note 3(B) for prior period restatements.*

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013	2012
Net earnings (loss)	**232**	(4)	(547)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**(20)**	31	(23)
Losses on derivatives designated as cash flow hedges, net of tax[2]	**(1)**	–	(2)
Reclassification of (gains) losses on derivatives designated as cash flow hedges to non-financial assets, net of tax[3]	**–**	1	5
Total items that will not be reclassified subsequently to net earnings	**(21)**	32	(20)
Gains (losses) on translating net assets of foreign operations	**75**	37	(23)
Reclassification of translation gains on net assets of divested foreign operations *(Note 4)*	**(7)**	–	–
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[4]	**(58)**	(35)	13
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[5] *(Note 4)*	**7**	–	–
Gains (losses) on derivatives designated as cash flow hedges, net of tax[6]	**215**	76	(12)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[7]	**(45)**	(24)	(6)
Total items that will be reclassified subsequently to net earnings	**187**	54	(28)
Other comprehensive income (loss)	**166**	86	(48)
Total comprehensive income (loss)	**398**	82	(595)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**348**	41	(626)
Non-controlling interests	**50**	41	31
	398	82	(595)

1 Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 11 expense, 2012 – 8 recovery).
2 Net of income tax of nil for the year ended Dec. 31, 2014 (2013 – nil, 2012 – 1 recovery).
3 Net of income tax of nil for the year ended Dec. 31, 2014 (2013 – 1 recovery, 2012 – 2 recovery).
4 Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 5 recovery, 2012 – 2 expense).
5 Net of income tax recovery of 1 for the year ended Dec. 31, 2014 (2013 – nil, 2012 – nil).
6 Net of income tax expense of 91 for the year ended Dec. 31, 2014 (2013 – 12 expense, 2012 – 4 expense).
7 Net of income tax expense of 3 for the year ended Dec. 31, 2014 (2013 – 1 expense, 2012 – 20 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013 *(Restated)**
Cash and cash equivalents	**43**	42
Trade and other receivables *(Note 12)*	**450**	504
Prepaid expenses	**17**	12
Risk management assets *(Notes 13 and 14)*	**273**	113
Inventory *(Note 15)*	**71**	77
	854	748
Investments *(Note 16)*	**-**	192
Long-term portion of finance lease receivables *(Note 7)*	**403**	377
Property, plant, and equipment *(Notes 17 and 35)*		
Cost	**12,532**	12,024
Accumulated depreciation	**(5,294)**	(4,831)
	7,238	7,193
Goodwill *(Notes 18 and 35)*	**462**	460
Intangible assets *(Notes 19 and 35)*	**331**	323
Deferred income tax assets *(Note 10)*	**45**	118
Risk management assets *(Notes 13 and 14)*	**402**	116
Other assets *(Notes 20 and 35)*	**98**	97
Total assets	**9,833**	9,624
Accounts payable and accrued liabilities	**481**	447
Current portion of decommissioning and other provisions *(Note 21)*	**34**	27
Risk management liabilities *(Notes 13 and 14)*	**128**	85
Income taxes payable	**2**	3
Dividends payable *(Note 24)*	**55**	85
Current portion of long-term debt and finance lease obligations *(Note 22)*	**751**	217
	1,451	864
Long-term debt and finance lease obligations *(Note 22)*	**3,305**	4,130
Decommissioning and other provisions *(Note 21)*	**322**	305
Deferred income tax liabilities *(Note 10)*	**434**	459
Risk management liabilities *(Notes 13 and 14)*	**94**	103
Defined benefit obligation and other long-term liabilities *(Notes 23 and 28)*	**349**	340
Equity		
Common shares *(Note 24)*	**2,999**	2,913
Preferred shares *(Note 25)*	**942**	781
Contributed surplus	**9**	9
Deficit	**(770)**	(735)
Accumulated other comprehensive income (loss) *(Note 26)*	**104**	(62)
Equity attributable to shareholders	**3,284**	2,906
Non-controlling interests *(Note 11)*	**594**	517
Total equity	**3,878**	3,423
Total liabilities and equity	**9,833**	9,624

* *See Note 3(B) for prior period restatements.*

Commitments *(Note 33)*

Contingencies *(Note 34)*

Subsequent events *(Note 36)*

See accompanying notes.

On behalf of the Board:

Gordon D. Giffin
Director

Karen E. Maidment
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2012	2,726	781	9	(362)	(136)	3,018	330	3,348
Net earnings (loss)	–	–	–	(33)	–	(33)	29	(4)
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and of tax	–	–	–	–	2	2	–	2
Net gains on derivatives designated as cash flow hedges, net of tax	–	–	–	–	41	41	12	53
Net actuarial gains on defined benefits plans, net of tax	–	–	–	–	31	31	–	31
Total comprehensive income				(33)	74	41	41	82
Common share dividends	–	–	–	(306)	–	(306)	–	(306)
Preferred share dividends	–	–	–	(38)	–	(38)	–	(38)
Formation of TransAlta Renewables Inc. *(Note 11)*	–	–	–	4	–	4	206	210
Distributions paid, and payable, to non-controlling interests	–	–	–	–	–	–	(60)	(60)
Common shares issued	187	–	–	–	–	187	–	187
Balance, Dec. 31, 2013	2,913	781	9	(735)	(62)	2,906	517	3,423
Net earnings	**–**	**–**	**–**	**182**	**–**	**182**	**50**	**232**
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	**–**	**–**	**–**	**–**	**17**	**17**	**–**	**17**
Net gains on derivatives designated as cash flow hedges, net of tax	**–**	**–**	**–**	**–**	**169**	**169**	**–**	**169**
Net actuarial losses on defined benefits plans, net of tax	**–**	**–**	**–**	**–**	**(20)**	**(20)**	**–**	**(20)**
Total comprehensive income				**182**	**166**	**348**	**50**	**398**
Common share dividends	**–**	**–**	**–**	**(196)**	**–**	**(196)**	**–**	**(196)**
Preferred share dividends	**–**	**–**	**–**	**(41)**	**–**	**(41)**	**–**	**(41)**
Secondary offering of TransAlta Renewables Inc. shares *(Note 11)*	**–**	**–**	**–**	**20**	**–**	**20**	**109**	**129**
Distributions paid, and payable, to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(82)**	**(82)**
Common shares issued	**86**	**–**	**–**	**–**	**–**	**86**	**–**	**86**
Preferred shares issued	**–**	**161**	**–**	**–**	**–**	**161**	**–**	**161**
Balance, Dec. 31, 2014	**2,999**	**942**	**9**	**(770)**	**104**	**3,284**	**594**	**3,878**

1 Refer to Note 26 for details on components of, and changes in, Accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2014**	2013	2012
Operating activities			
Net earnings (loss)	**232**	(4)	(547)
Depreciation and amortization *(Note 35)*	**595**	585	564
Gain on sale of assets *(Note 4)*	**(2)**	(12)	(3)
California claim *(Note 8)*	**(28)**	28	–
Accretion of provisions *(Note 21)*	**18**	18	17
Decommissioning and restoration costs settled *(Note 21)*	**(16)**	(24)	(34)
Deferred income tax expense (recovery) *(Note 10)*	**(26)**	(47)	89
Unrealized (gain) loss from risk management activities	**(50)**	76	99
Unrealized foreign exchange (gain) loss	**11**	(1)	5
Provisions	**–**	11	11
Asset impairment charges (reversals) *(Note 6)*	**(6)**	(18)	324
Sundance Units 1 and 2 return to service *(Note 8)*	**–**	25	43
Equity loss, net of distributions received *(Note 16)*	**–**	10	14
Other non-cash items	**(5)**	44	(6)
Cash flow from operations before changes in working capital	**723**	691	576
Change in non-cash operating working capital balances *(Note 30)*	**73**	74	(56)
Cash flow from operating activities	**796**	765	520
Investing activities			
Additions to property, plant, and equipment *(Notes 17 and 35)*	**(487)**	(561)	(703)
Additions to intangibles *(Notes 19 and 35)*	**(34)**	(32)	(39)
Acquisition of finance lease *(Note 4)*	**–**	–	(312)
Addition to assets held for sale	**(13)**	(17)	–
Proceeds on sale of property, plant, and equipment	**6**	14	3
Proceeds on sale of investments and development projects *(Note 4)*	**224**	–	3
Resolution of certain outstanding tax matters *(Note 10)*	**–**	2	9
Realized gains (losses) on financial instruments	**(2)**	14	(13)
Net decrease in collateral received from counterparties	**(1)**	(1)	(13)
Net (increase) decrease in collateral paid to counterparties	**(3)**	–	24
Decrease in finance lease receivable	**3**	1	3
Acquisition of Wyoming wind farm *(Note 4)*	**–**	(109)	–
Other	**13**	15	(8)
Change in non-cash investing working capital balances	**2**	(29)	(2)
Cash flow used in investing activities	**(292)**	(703)	(1,048)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 22)*	**(436)**	(119)	152
Repayment of long-term debt *(Note 22)*	**(551)**	(328)	(314)
Issuance of long-term debt *(Note 22)*	**434**	398	388
Dividends paid on common shares *(Note 24)*	**(140)**	(116)	(104)
Dividends paid on preferred shares *(Note 25)*	**(41)**	(38)	(32)
Net proceeds on issuance of common shares *(Note 24)*	**–**	–	293
Net proceeds on issuance of preferred shares *(Note 25)*	**161**	–	217
Net proceeds on sale of non-controlling interest in subsidiary *(Note 11)*	**129**	207	–
Realized gains (losses) on financial instruments	**35**	15	(31)
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(84)**	(55)	(59)
Decrease in finance lease obligations *(Note 22)*	**(10)**	(9)	–
Other	**–**	(2)	(6)
Cash flow from (used in) financing activities	**(503)**	(47)	504
Cash flow from (used in) operating, investing, and financing activities	**1**	15	(24)
Effect of translation on foreign currency cash	**–**	–	2
Increase (decrease) in cash and cash equivalents	**1**	15	(22)
Cash and cash equivalents, beginning of year	**42**	27	49
Cash and cash equivalents, end of year	**43**	42	27
Cash income taxes paid	**31**	46	30
Cash interest paid	**230**	240	234

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. Its head office is located in Calgary, Alberta.

The three reportable segments of the Corporation are as follows:

I. Generation

The Generation Segment owns and operates hydro, wind, 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. Starting in 2013, electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Generation Segment.

II. Energy Marketing

The Segment changed its name from "Energy Trading" in 2014 following a shift in focus toward lower risk revenue generation activities such as asset optimization, customer fee and margin-based growth, and arbitrage trading.

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

Energy Marketing 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 Marketing is also responsible for recommending portfolio optimization decisions. The results of these other 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, aboriginal relations, internal audit, and other administrative support to the Generation and Energy Marketing segments. Charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

These consolidated financial statements have been prepared by management in compliance with IFRS as issued by the International Accounting Standards Board ("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 on Feb. 18, 2015.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists when the Corporation is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Significant Accounting Policies

A. 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 measured reliably. Revenue from the rendering of services is 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 leases are recognized as outlined in *Note 2(R)*.

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn 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 revenue. 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.

B. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint arrangements 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 arrangements 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 (Loss) ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income (Loss) ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in a foreign net investment as a result of a disposal, partial disposal, or loss of control.

C. 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 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 assessed for impairment on an ongoing basis and at reporting dates. An impairment may exist if an incurred loss event has arisen that has an impact on the recoverability of the financial asset. Factors that may indicate an incurred loss event and related impairment may exist include, for example: a debtor is experiencing significant financial difficulty, or a debtor has or it is probable that they will enter bankruptcy or other financial reorganization. The carrying amount of financial assets, such as receivables, is reduced for impairment losses through the use of an allowance account, and the loss is recognized in net earnings.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Financial assets and financial liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

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 is recognized in OCI. Derivatives used in commodity risk management activities are described in more detail in *Note 2(A)*.

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 recognized assets and liabilities 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 hedge criteria are not met or the Corporation does not apply hedge accounting, 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.

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 derivative's cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. 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 the forecasted transaction is no longer expected to 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, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair 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 fair 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 related fair values are recorded in risk management assets or liabilities, as appropriate. 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.

D. Cash and Cash Equivalents

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

E. 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.

F. Inventory

I. Fuel

The Corporation's inventory balance is comprised of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value.

The cost of internally produced coal inventory is determined using absorption costing, which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions 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 Marketing

Commodity inventories held in the Energy Marketing 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.

G. 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.

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized.

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:

Coal 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 *(see Note 2(S))*. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

H. 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, and probable future economic benefits of the intangible asset, 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 is included in depreciation and amortization and fuel and purchased power in the Consolidated Statements of Earnings (Loss).

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 intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

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

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Corporation assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

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 occurs 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 operations, 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 of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified an appropriate valuation model such as discounted cash flows is used. 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. 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 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.

J. 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 or groups of 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 or groups of 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 or groups of CGUs to which the goodwill relates is compared to its carrying amount. 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.

K. Project Development Costs

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. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. 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 income 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 income tax is charged or credited to net earnings, except when related 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 income 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.

M. Employee Future Benefits

The Corporation has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, 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. Re-measurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Re-measurements are not reclassified to profit or loss, from OCI, in subsequent periods.

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.

N. 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, remeasured 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 determines 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 *(see Note 2(G))*. 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.

O. Share-Based Payments

The Corporation measures share-based awards compensation expense at grant date fair value and recognizes the expense over the vesting period based on the Corporation's estimate of the number of units that will eventually vest. Any award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation expense associated with equity-settled and cash-settled awards are recognized within equity and liability, respectively. The liability associated with cash-settled awards is remeasured to fair value at each reporting date up to, and including, the settlement date, with changes in fair value recognized within compensation expense.

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded 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 the amounts are recognized as revenue in the period of recovery.

Emission credits and allowances that are held for trading and 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.

Q. 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 of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position.

R. 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 (e.g. 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 lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings (Loss).

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 rent, from operating leases is recognized over the term of the arrangement and is reflected in revenue on the Consolidated Statements of Earnings (Loss). 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.

Leasing or other contractual arrangements that transfer substantially all of the risks and rewards of ownership to the Corporation are considered finance leases. A leased asset and lease obligation are recognized at the lower of the fair value or the present value of the minimum lease payments. Lease payments are apportioned between interest expense and a reduction of the lease liability. Contingent rents are charged as expenses in the periods incurred. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

S. 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.

T. 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 initially 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 control.

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.

U. Joint Arrangements

A joint arrangement 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 arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets, and obligations for the liabilities, relating to the arrangement. 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 operation. The Corporation reports its interests in joint operations 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 operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Corporation reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Corporation and joint ventures is eliminated based on the Corporation's ownership interest. Distributions received from joint ventures 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 joint venture 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 joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. 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 of disposal.

V. Government Incentives

Government incentives are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the incentive and that the incentive will be received. When the incentive 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 incentive 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.

W. Earnings per Share

Basic earnings per share is calculated by dividing net earnings attributable to common shareholders by the weighted average number of common shares outstanding in the year.

Diluted earnings per share is calculated by dividing net earnings attributable to common shareholders, adjusted for the after-tax effects of dividends, interest or other changes in net earnings that would result from potential dilutive instruments, by the weighted average number of common shares outstanding in the year, adjusted for additional common shares that would have been issued on the conversion of all potential dilutive instruments.

X. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition-date fair values. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed.

Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

Y. Stripping Costs

A mine stripping activity asset is recognized when all of the following are met: i) it is probable that the future benefit associated with improved access to the coal reserves associated with the stripping activity will be realized; ii) the component of the coal reserve to which access has been improved can be identified; and iii) the costs related to the stripping activity associated with that component can be measured reliably. Costs include those directly incurred to perform the stripping activity as well as an allocation of directly attributable overheads. The resulting stripping activity asset is amortized on a unit-of-production basis over the expected useful life of the identified component that it relates to. The amortization is recognized as a component of the standard cost of coal inventory.

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of 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, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and 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, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is 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 of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs, and other related cash inflows and outflows over the life of the facilities, 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 facilities. Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity, and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. 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. Information regarding determinations of CGUs for asset and goodwill impairment testing can be found in *Notes 6 and 18*. Key assumptions used in determining the 2014 and 2012 recoverable amount of the Centralia coal plant and the 2012 recoverable amount of Sundance Units 1 and 2 are further explained in *Note 6*.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal 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 and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

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 income taxes currently payable and income 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 uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. 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 amounts 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 also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Joint Control

In January 2014, the Corporation, through a wholly owned subsidiary, formed an unincorporated joint venture named Fortescue River Gas Pipeline, of which it has a 43 per cent interest. Management, using judgment, assessed whether the Corporation's sole partner had control over the joint venture, or whether joint control existed. The contractual terms of the joint venture agreement and the management agreement were reviewed and management concluded that joint control exists as decisions regarding the relevant activities of the joint venture require a special majority vote (at least 70 per cent in favour). Accordingly, the business is accounted for as a joint operation.

VI. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in *Note 2(K)*. 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.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in *Note 2(N)* 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.

VIII. 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.

IX. 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 pension and 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 rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employment 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.

X. 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.

3. Accounting Changes

A. Adoption of New or Amended IFRS

On Jan. 1, 2014, the Corporation adopted the following new or amended accounting standards and interpretations that were previously issued by the IASB. There was no impact of adopting these on the consolidated financial statements.

I. Offsetting Financial Assets and Financial Liabilities – IAS 32 *Financial Instruments: Presentation*

The amendments clarify the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements.

II. Recoverable Amount Disclosures for Non-Financial Assets – IAS 36 *Impairment of Assets*

The amendments remove the unintended consequences that IFRS 13 *Fair Value Measurement* had on the disclosures required under IAS 36 and require disclosure of the recoverable amounts for assets or CGUs for which a significant impairment loss has been recognized or reversed. The amendment was evaluated for application retrospectively from the date of initial application of IFRS 13 *Fair Value Measurement*, Jan. 1, 2013.

B. Other Current Accounting Changes

I. Inception Gains and Losses

The Corporation restated the Consolidated Statement of Financial Position as at Dec. 31, 2013 to reclassify the inception gains or losses arising from differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. These amounts were previously reported as gross contra-risk management assets or liabilities. The adjustment reclassifies them as direct offsets to the value of the derivative contract to which they relate. As a result of the adjustment, long-term risk management assets and long-term risk management liabilities were each reduced by $160 million at Dec. 31, 2013. Corresponding adjustments to the Dec. 31, 2012 Consolidated Statement of Financial Position were immaterial. Refer to *Note 13(C)* for further information on inception gains and losses.

II. Inventory Writedown

The Corporation restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify inventory writedown as a component of fuel and purchased power. These amounts were previously reported as standalone components of operating income. The adjustment is intended to better capture within gross margin the generally offsetting effects that changes in future power prices have on mark-to-market gains or losses from economic forward power sale hedges, included in revenue, and on inventory writedown or reversals. As a result of the adjustment, fuel and purchased power for the years ended Dec. 31, 2013 and 2012 increased by $22 million and $44 million, respectively. The inventory writedown for the year ended Dec. 31, 2014 was $19 million.

III. Net Other Operating Income and Losses

The Corporation restated the Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2013 and 2012 to reclassify the losses associated with the California claim, the Sundance Units 1 and 2 return to service, and the assumption of pension obligations, as well as gains from insurance recoveries, as a net other operating income and losses group within operating income. Previously, each item was presented in earnings outside of operating income. The Corporation initiated the change as part of its ongoing monitoring of practices concerning additional IFRS measures. As a result of the change, operating income (loss) for the years ended Dec. 31, 2013 and 2012 decreased by $102 million and $254 million, respectively.

C. Comparative Figures

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

D. Future Accounting Changes

Accounting standards that have been previously issued by the IASB, but are not yet effective and have not been applied by the Corporation, include:

I. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments.* IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e. recognition of credit losses), and a new hedge accounting model.

Under the classification and measurement requirements for financial assets, financial assets must be classified and measured at either amortized cost or at 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.

The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities 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.

The new general hedge accounting model is intended to be simpler and more closely focus on how an entity manages its risks, replaces the IAS 39 effectiveness testing requirements with the principle of an economic relationship, and eliminates the requirement for retrospective assessment of hedge effectiveness.

The new requirements for impairment of financial assets introduce an expected loss impairment model that requires more timely recognition of expected credit losses. IAS 39 impairment requirements are based on an incurred loss model where credit losses are not recognized until there is evidence of a trigger event.

IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers,* which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. IFRS 15 is effective for annual reporting periods beginning on or after Jan. 1, 2017 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

4. Acquisitions and Disposals

During 2012, 2013, and 2014, the following acquisitions and disposals took place in the Generation Segment:

A. Acquisitions

I. 2013

On Dec. 20, 2013, the Corporation completed the acquisition of a 144 megawatt ("MW") wind farm in Wyoming ("Wyoming wind farm") from an affiliate of NextEra Energy Resources, LLC. The total cash consideration transferred was U.S.$102 million ($109 million). The acquisition was TransAlta's first wind project in the U.S.

At the acquisition date, the fair value of assets acquired and liabilities assumed was as follows:

Assets:	
Property, plant, and equipment	79
Intangible assets	20
Goodwill	13
Total assets acquired	112
Liabilities:	
Decommissioning and restoration provision	3
Total consideration transferred	**109**

Goodwill arose in the acquisition primarily as a result of the expectation by the Corporation of future market growth and development opportunities in the region. These benefits are not recognized separately from goodwill as they do not meet the recognition criteria for identifiable intangible assets. All of the goodwill is expected to be deductible for tax purposes.

II. 2012

On Sept. 28, 2012, the Corporation acquired the 125 MW Solomon power station located in Western Australia from Fortescue Metals Group Ltd. ("Fortescue") for U.S.$318 million. The facility is fully contracted with Fortescue under a long-term Power Purchase Agreement ("Agreement") with an initial term of 16 years commencing in October 2012, after which Fortescue will have the option to either extend the Agreement for an additional five years under the same terms or to acquire the facility. The Corporation has accounted for the facility and associated Agreement as a finance lease with TransAlta being the lessor *(see Note 7)*.

B. Disposals

I. 2014

On June 12, 2014, the Corporation closed the sale of its 50 per cent ownership of CE Generation, LLC ("CE Gen"), CalEnergy LLC, and the Blackrock development project to MidAmerican Renewables for gross proceeds of U.S.$200.5 million. The original consideration of U.S.$188.5 million was increased as a result of a U.S.$12 million contribution made by the Corporation in May 2014. As a result of the sale, the Corporation recognized a pre-tax gain of $1 million ($2 million after-tax) as part of gain on sale of assets.

On Nov. 25, 2014, the Corporation closed the sale of its 50 per cent ownership of Wailuku Holding Company, LLC for gross proceeds of U.S.$5 million. A pre-tax gain of $1 million ($1 million after-tax) was recognized as part of gain on sale of assets.

The gains include reclassified cumulative translation gains of $7 million on the divested net assets, offset by related cumulative after-tax losses of $7 million from the related net investment hedge.

II. 2013

During 2013, the Corporation realized a pre-tax gain of $10 million relating to the sale of land and a pre-tax gain of $2 million relating to the sale of British Columbia water rights.

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2014		2013 (Restated)*		2012 (Restated)*	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**937**	**-**	778	-	645	-
Coal inventory writedown	**19**	**-**	22	-	44	-
Purchased power	**75**	**-**	85	-	63	-
Mine depreciation	**56**	**-**	58	-	41	-
Salaries and benefits	**5**	**280**	5	251	4	261
Other operating expenses	**-**	**262**	-	265	-	238
Total	**1,092**	**542**	948	516	797	499

* *See Note 3(B) for prior period restatements.*

6. Asset Impairment Charges and Reversals

All impairment charges and reversals are reported in the Generation Segment.

A. 2014

I. Centralia Coal

As at Nov. 30, 2014, the Corporation identified the decrease in projected growth in Mid-Columbia power prices as an indicator that the Centralia coal CGU could be impaired. The Centralia coal CGU's carrying amount at that date, net of associated long-term liabilities, was $372 million. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	U.S.$31.00 to 52.00 per MWh
On-highway diesel fuel on coal shipments	U.S.$3.06 to 3.37 per gallon
Discount rates	5.1 to 6.2 per cent

The valuation is subject to measurement uncertainty based on those assumptions, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses, and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period extended to the assumed decommissioning of the asset, after its projected cessation of operation in its current form in 2025.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded. Any adverse change in assumptions, in isolation, would have resulted in an impairment charge being recorded. The Corporation continues to manage risks associated with the CGU through optimization of its operating activities and capital plan.

II. Centralia Gas

During 2014, the Corporation sold to external counterparties and transferred to other owned facilities for productive use, assets of the Centralia gas facility, which had been fully impaired and had remained idled since 2010. As a result of the transactions, the Corporation recognized pre-tax impairment reversals of $5 million.

B. 2013

I. Alberta Merchant

As part of the annual impairment review and assessment process in 2013, it was determined that the Corporation's Alberta plants that have significant merchant capacity should be considered one cash-generating unit (the "Alberta Merchant CGU"). Previously, each plant was assessed for impairment individually. The reasons for this change include consideration of the final regulations published by the Canadian federal government in September 2012 governing greenhouse gas emissions and the 50-year total life for Canadian coal-fired power plants; and the Corporation's refinement of its risk management approach and practices regarding its Alberta wholesale market price exposure. The final regulations confirmed additional operating time and increased flexibility for the Corporation's Alberta coal plants and led, in part, to the Corporation broadening its view on the management of its Alberta wholesale market price exposure.

The Corporation reversed previous pre-tax impairment losses of $23 million on various renewables plants that became part of the Alberta Merchant CGU. The Alberta Merchant CGU's recoverable amount was based on an estimate of fair value less costs of disposal using a discounted cash flow methodology, based on the Corporation's long-range forecasts and prices evidenced in the marketplace. Due to a substantial excess of fair value over net book value at other plants included within the Alberta Merchant CGU, valuation assumptions and methodologies were not a significant driver of the impairment reversals.

II. Renewables

During 2013, the Corporation recognized a total pre-tax impairment charge of $4 million related to three contracted hydro assets. The assets were impaired primarily due to an increase in future capital and operating expenses that resulted from the completion of condition assessments. The annual impairment assessments were based on estimates of fair value less costs of disposal derived from long-range forecasts.

C. 2012

I. Sundance Units 1 and 2

During 2012, the Corporation reversed $41 million of the $43 million impairment losses previously taken on Sundance Units 1 and 2. The reversal arose as a result of the additional years of merchant operations expected to be realized at Units 1 and 2 due to amendments to Canadian federal regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation. The previous draft regulations proposed shutdown after 45 years. The impairment assessment was based on an estimate of fair value less costs of disposal, derived from the cash flows expected to result over the revised useful life of the Units, taking into consideration the provisions of the PPA and prices evidenced in the marketplace.

II. Centralia Coal

The TransAlta Energy Bill and a Memorandum of Agreement was signed on Dec. 23, 2011 that provided a framework for the orderly transition from coal-fired energy produced at the Centralia coal plant and the shutdown of the units in 2020 and 2025. On July 25, 2012, the Corporation announced that it entered into a long-term power agreement to provide electricity from the Centralia coal plant from December 2014 until the facility is fully retired in 2025. As a result of these agreements, the Corporation recognized a pre-tax impairment charge of $347 million during 2012. The impairment assessment was based on whether the carrying amount of the Centralia coal plant was recoverable based on an estimate of fair value less costs of disposal.

III. Renewables

During 2012, the Corporation recognized a pre-tax impairment charge of $18 million related to five assets. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs of disposal, derived from the long-range forecasts and prices evidenced in the marketplace. The assets were impaired primarily due to expectations regarding lower market prices.

7. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases, comprised of the Fort Saskatchewan cogeneration facility and the Solomon power station finance leases, are as follows:

As at Dec. 31	2014		2013	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	55	51	50	46
Second to fifth years inclusive	229	157	209	143
More than five years	479	162	494	160
	763	370	753	349
Less: unearned finance lease income	546	-	548	-
Add: unguaranteed residual value	191	38	175	31
Total finance lease receivables	408	408	380	380
Current portion of finance lease receivables *(Note 12)*	5		3	
Long-term portion of finance lease receivables	403		377	
	408		380	

8. Net Other Operating (Income) Losses

Net other operating (income) losses are comprised of the following:

Year ended Dec. 31	2014	2013	2012
California claim	5	56	-
Insurance recoveries	(10)	(8)	-
Supplier settlement	(9)	-	-
Sundance Units 1 and 2 return to service	-	25	254
Loss on assumption of pension obligations	-	29	-
Net other operating (income) losses	(14)	102	254

A. California Claim

On May 30, 2014, the Corporation announced that its settlement with California utilities, the California Attorney General and certain other parties (the "California Parties") to resolve claims related to the 2000-2001 power crisis in the State of California had been approved by the Federal Energy Regulatory Commission. The settlement provides for the payment by the Corporation of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to the Corporation from accounts receivable. The first payment of U.S.$26 million was paid in June 2014 and the second is due in 2015. In 2013, the Corporation accrued for the then expected settlement of these disputes with the California Parties, which resulted in a pre-tax charge to 2013 earnings of approximately U.S.$52 million. The finalization of the settlement in May 2014 resulted in an additional pre-tax charge to 2014 earnings of U.S.$5 million.

B. Insurance Recoveries

During 2014, the Corporation received $28 million (2013 – $15 million) in insurance proceeds, of which $18 million (2013 – $7 million) was related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in June 2013 and was accounted for as a reduction to period operations, maintenance, and administration. The balance, in the amount of $10 million (2013 – $8 million) related to purchases of replacement equipment and business interruption insurance for various prior years' claims.

C. Supplier Settlement

During 2014, the Corporation settled a dispute with a supplier in relation to an equipment failure in prior years.

D. Sundance Units 1 and 2 Return to Service

In December 2010, Units 1 and 2 of the Corporation's Sundance facility were shut down due to conditions observed in the boilers at both units. On July 20, 2012, an arbitration panel concluded that Unit 1 and Unit 2 were not economically destroyed under the terms of the PPA and the Corporation was required to restore the units to service. For the year ended Dec. 31, 2012, a $254 million pre-tax impact of the ruling has been recognized. During 2013, $25 million of components were retired as a result of the work completed on the units to return them to service. Sundance Unit 1 returned to service on Sept. 2, 2013 and Unit 2 returned to service on Oct. 4, 2013.

E. Loss on Assumptions of Pension Obligations

Effective Jan. 17, 2013, the Corporation assumed, through its wholly owned subsidiary, SunHills Mining Limited Partnership ("SunHills"), operations and management control of the Highvale mine from Prairie Mines and Royalty Ltd. ("PMRL"). PMRL employees working at the Highvale mine were offered employment by SunHills, which agreed to assume responsibility for certain pension plan and pension funding obligations, which the Corporation previously funded through the payments made under the PMRL mining contracts. As a result, a pre-tax loss of $29 million was recognized in 2013, along with the corresponding liabilities.

9. Net Interest Expense

The components of net interest expense, which excludes finance lease income, are as follows:

Year ended Dec. 31	**2014**	2013	2012
Interest on debt	**238**	240	227
Interest income	**–**	–	(2)
Capitalized interest *(Note 17)*	**(3)**	(2)	(4)
Ineffectiveness on hedges	**–**	–	4
Interest on finance lease obligations	**1**	–	–
Accretion of provisions *(Note 21)*	**18**	18	17
Net interest expense	**254**	256	242

10. Income Taxes

A. Consolidated Statements of Earnings (Loss)

I. Rate Reconciliations

Year ended Dec. 31	2014	2013	2012
Earnings (loss) before income taxes	**239**	(12)	(445)
Equity loss	**-**	10	15
Net earnings attributable to non-controlling interests	**(37)**	(29)	(37)
Adjusted earnings (loss) before income taxes	**202**	(31)	(467)
Statutory Canadian federal and provincial income tax rate *(%)*	**25.0**	25.0	25.0
Expected income tax expense (recovery)	**51**	(8)	(117)
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(3)**	(21)	(49)
Resolution of uncertain tax matters	**(1)**	(1)	(27)
Divestiture of investment	**(38)**	-	-
Statutory and other rate differences	**-**	(5)	7
Writedown (reversal of writedown) of deferred income tax assets	**(5)**	28	289
Other	**3**	(1)	(1)
Income tax expense (recovery)	**7**	(8)	102
Effective tax rate *(%)*	**3**	26	(22)

II. Components of Income Tax Expense

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

Year ended Dec. 31	2014	2013	2012
Current income tax expense	**33**	38	27
Adjustments in respect of current income tax of previous years	**-**	1	(3)
Adjustments in respect of deferred income tax of previous years	**2**	(1)	1
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**12**	(68)	(71)
Deferred income tax expense (recovery) resulting from changes in tax rates or laws	**-**	(5)	7
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce current income tax expense	**-**	-	(11)
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**(35)**	(1)	(16)
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets	**(5)**	28	168
Income tax expense (recovery)	**7**	(8)	102

Year ended Dec. 31	2014	2013	2012
Current income tax expense	**33**	39	13
Deferred income tax expense (recovery)	**(26)**	(47)	89
Income tax expense (recovery)	**7**	(8)	102

For the year ended Dec. 31, 2013, the Corporation wrote off deferred income tax assets of $28 million (2012 – $289 million) related to approximately $80 million (2012 – $826 million) of deductible temporary differences of its U.S. operations. The deferred income tax assets related mainly to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The deferred tax assets were written off as it was no longer considered probable that sufficient taxable income would be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. For the year ended Dec. 31, 2014, $5 million of previously written off deferred income tax assets was reversed based on changes to taxable and deductible temporary differences that impact the net U.S. deferred income tax assets. Net operating losses expire between 2021 and 2034.

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	2014	2013	2012
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**88**	12	(15)
Net impact related to net investment hedges	**(8)**	(5)	2
Net actuarial gains (losses)	**(7)**	11	(8)
Common and preferred share issuance costs	**(1)**	–	(5)
Income tax expense (recovery) reported in equity	**72**	18	(26)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2014	2013
Net operating loss carryforwards	**716**	665
Future decommissioning and restoration costs	**101**	91
Property, plant, and equipment	**(916)**	(923)
Risk management assets and liabilities, net	**(144)**	(24)
Employee future benefits and compensation plans	**68**	60
Interest deductible in future periods	**81**	63
Allowance for doubtful accounts	**–**	18
Foreign exchange differences on U.S.-denominated debt	**48**	6
Deferred coal rights revenue	**14**	13
Other deductible temporary differences	**2**	7
Net deferred income tax liability, before writedown of deferred income tax assets	**(30)**	(24)
Writedown of deferred income tax assets	**(359)**	(317)
Net deferred income tax liability, after writedown of deferred income tax assets	**(389)**	(341)

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2014	2013
Deferred income tax assets[1]	**45**	118
Deferred income tax liabilities	**(434)**	(459)
Net deferred income tax liability	**(389)**	(341)

1 The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2014, the Corporation had recognized a net liability of $7 million (2013 – $8 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

Balance, Dec. 31, 2012	(9)
Increase as a result of tax positions taken during a prior period	(3)
Decrease as a result of settlements with taxation authorities	4
Balance, Dec. 31, 2013	(8)
Decrease as a result of settlements with taxation authorities	1
Balance, Dec. 31, 2014	**(7)**

11. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owned by
TransAlta Cogeneration L.P.	49.99% – Canadian Power Holdings Inc.
TransAlta Renewables	29.70% – Public shareholders[1]
Kent Hills wind farm[2]	17% – Natural Forces Technologies Inc.

1 *As at Dec. 31, 2013, the non-controlling interest was 19.3%.*
2 *Owned by TransAlta Renewables.*

TransAlta Cogeneration, L.P. operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of 28 renewable power generation facilities in Canada and owns an economic interest in a wind facility in the U.S.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Cogeneration L.P.

Year ended Dec. 31	**2014**	2013	2012
Revenues	**305**	295	306
Net earnings	**71**	48	69
Total comprehensive income	**72**	71	57
Amounts attributable to the non-controlling interest:			
Net earnings	**35**	24	34
Total comprehensive income	**35**	36	28
Distributions paid to Canadian Power Holdings Inc.	**56**	46	55

As at Dec. 31	**2014**	2013
Current assets	**58**	56
Long-term assets	**588**	632
Current liabilities	**(64)**	(56)
Long-term liabilities	**(59)**	(68)
Total equity	**(523)**	(564)
Equity attributable to Canadian Power Holdings Inc.	**(260)**	(280)

B. TransAlta Renewables

On May 28, 2013, the Corporation formed a new subsidiary, TransAlta Renewables, to provide investors with the opportunity to invest directly in a highly contracted portfolio of renewable power generation facilities. The Corporation retains control over TransAlta Renewables, and therefore consolidates TransAlta Renewables.

On Aug. 9, 2013, the Corporation transferred 28 indirectly owned wind and hydroelectric generating assets to TransAlta Renewables through the sale of all the issued and outstanding shares of two subsidiaries: Canadian Hydro Developers, Inc. ("CHD") and Western Sustainable Power Inc. On Aug. 29, 2013, TransAlta Renewables completed an Initial Public Offering and issued 22.1 million common shares for gross proceeds of $221 million. After completion of these transactions and at Dec. 31, 2013, the Corporation owned 92.6 million common shares of TransAlta Renewables, representing an 80.7 per cent ownership interest. In total, the Corporation received $207 million in cash consideration net of commissions and expenses. The excess of consideration received over the net book value of the Corporation's divested interest was $4 million and was recognized in retained earnings (deficit).

On April 29, 2014, the Corporation completed a secondary offering of 11,950,000 common shares of TransAlta Renewables at a price of $11.40 per common share. The offering resulted in gross proceeds to the Corporation of approximately $136 million. Following completion of the offering and at Dec. 31, 2014, TransAlta owns approximately 70.3 per cent of the common shares of TransAlta Renewables. As a result of the transaction, the carrying amount of the non-controlling interests was increased by $109 million to reflect the approximate 10.4 per cent increase in their relative interest in TransAlta Renewables and a $20 million gain, net of tax and issuance costs, attributable to common shareholders, was recognized directly in retained earnings (deficit).

Non-controlling interest in TransAlta Renewables arose on formation of the subsidiary in August 2013, and 2012 comparative information is, therefore, not provided. The net earnings, distributions, and equity attributable to non-controlling interests includes the 17 per cent non-controlling interest in the 150 MW Kent Hills wind farm, located in New Brunswick.

Year ended Dec. 31	**2014**	2013
Revenues	**233**	245
Net earnings	**52**	53
Total comprehensive income	**52**	54
Amounts attributable to the non-controlling interests:		
Net earnings and total comprehensive income	**15**	5
Distributions paid to non-controlling interests	**28**	9

As at Dec. 31	**2014**	2013
Current assets	**61**	59
Long-term assets	**1,903**	1,954
Current liabilities	**(241)**	(100)
Long-term liabilities	**(682)**	(846)
Total equity	**(1,041)**	(1,067)
Equity attributable to non-controlling interests	**(334)**	(237)

12. Trade and Other Receivables

As at Dec. 31	**2014**	2013
Gross trade accounts receivable	**415**	522
Allowance for doubtful accounts	**-**	(49)
Net trade receivables	**415**	473
Income taxes receivable	**5**	8
Current portion of finance lease receivables *(Note 7)*	**5**	3
Collateral paid *(Note 14)*	**25**	20
Trade and other receivables	**450**	504

The change in the allowance for doubtful accounts is as follows:

Balance, Dec. 31, 2012	46
Change in foreign exchange rates	3
Balance, Dec. 31, 2013	49
Change in foreign exchange rates	7
Settlement of California claim *(Note 8)*	(56)
Balance, Dec. 31, 2014	-

13. 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 *(see Note 2(C))*. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2014

	Derivatives used for hedging	**Derivatives classified as held for trading**	**Loans and receivables**	**Other financial liabilities**	**Total**
Financial assets					
Cash and cash equivalents	–	–	43	–	43
Trade and other receivables	–	–	450	–	450
Long-term portion of finance lease receivables	–	–	403	–	403
Risk management assets					
Current	93	180	–	–	273
Long-term	393	9	–	–	402
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	481	481
Dividends payable	–	–	–	55	55
Risk management liabilities					
Current	39	89	–	–	128
Long-term	75	19	–	–	94
Long-term debt and finance lease obligations[1]	–	–	–	4,056	4,056

Carrying value as at Dec. 31, 2013 *(Restated – see Note 3(B))*

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	–	–	42	–	42
Trade and other receivables	–	–	504	–	504
Long-term portion of finance lease receivables	–	–	377	–	377
Risk management assets					
Current	17	96	–	–	113
Long-term	90	26	–	–	116
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	447	447
Dividends payable	–	–	–	85	85
Risk management liabilities					
Current	20	65	–	–	85
Long-term	72	31	–	–	103
Long-term debt and finance lease obligations[1]	–	–	–	4,347	4,347

1 *Includes current portion.*

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. 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. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Levels I, II, and III Fair Value Measurements and Transfers between Fair Value Levels

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation 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 on the lowest level input that is significant to the derivation of the fair value.

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 at the measurement date. 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, credit valuation, and location differentials. The Corporation's commodity risk management Level II financial instruments 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 and long-term debt measured and carried at fair value, 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.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models 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.

The Corporation also has various contracts with terms that extend beyond a liquid trading period. As forward market prices 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.

The Corporation has a Commodity Exposure Management Policy (the "Policy"), which 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 trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by the Corporation's risk management department. Level III fair values are calculated within the Corporation's energy trading risk management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III commodity risk management financial instruments fair values are determined at Dec. 31, 2014 is estimated to be a +/- $120 million (2013 +/- $105 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. An amount of +/- $92 million (2013 +/- $87 million) in the stress value stems from a long-dated power sale contract that is designated as a cash flow hedge, while the remaining +/-$28 million (2013 +/- $18 million) accounts for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Information about the significant unobservable inputs used in determining Level III fair values is as follows:

Description	**Effects on fair value as at Dec. 31, 2014**	**Valuation technique**	**Unobservable input**	**Range**
Unit contingent power purchases	(53)	Historical bootstrap	Price discount Volumetric discount[1]	0.3-1.5 per cent 0-10 per cent
Long-term power sale – Alberta	(13)	Long-term price forecast	Illiquid future power prices (per MWh)	$91-$99
Long-term power sale – U.S.	511	Long-term price forecast	Illiquid future power prices (per MWh)	U.S.$41-U.S.$50
Coal supply revenue sharing	(1)	Black-Scholes and exotic valuation techniques	Volumes (MWh) Illiquid commodity forward price volatilities Illiquid future power prices (per MWh) Illiquid future coal prices (per ton)	17-25 per cent of available generation 13-36 per cent U.S.$22-U.S.$62 U.S.$14-U.S.$16
Unit contingent power sales	(3)	Black-Scholes	Illiquid commodity forward price volatilities	32-67 per cent
Transmission and financial transmission rights	(1)	Historical bootstrap	Illiquid forward power price spreads (per MWh)	U.S.$(12)-U.S.$13 and $0-$6
Structured products in Eastern markets	3	Option valuation techniques and historical bootstrap	Implied volatilities Correlations Non-standard shape factors	26-86 per cent 53-82 per cent 69-103 per cent

1 *A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.*

Description	Effects on fair value as at Dec. 31, 2013	Valuation technique	Unobservable input	Range
Unit contingent power purchases	43	Historical bootstrap	Price discount Volumetric discount[1]	0-2 per cent 0-14 per cent
Long-term power sale – Alberta	(9)	Long-term price forecast	Illiquid future power prices (per MWh)	$52-$91
Long-term power sale – U.S.	234	Long-term price forecast	Illiquid future power prices (per MWh)	U.S.$32-U.S.$79
Coal supply revenue sharing	(12)	Black-Scholes	Volumes (MWh) Illiquid future implied volatilities in MidC power	18-25 per cent of available generation 35 per cent
Unit contingent power sales	(5)	Black-Scholes	Illiquid commodity forward price volatilities	55 per cent

1 *A change in the volumetric discount, could, depending on other market dynamics, result in a directionally similar change in the price discount.*

The effects on fair values of significant unobservable inputs exclude the effects of observable inputs such as liquidity and credit discounts.

d. Transfers between Fair Value Levels

Fair value Level transfers can occur where the availability of inputs that are used to determine fair values have changed. A transfer from Level III to Level II occurs where inputs that were not readily observable have become observable during the period. The Corporation's policy is for Level transfers to occur at the end of each period. During 2014, there were no (2013 – $28 million) fair value transfers from Level III net commodity risk management assets to Level II net commodity risk management assets. During 2013, the contract terms were determined to be within a liquid trading period where observable prices were available. Previously, the trade terms of these contracts were beyond a liquid trading period where forward price forecasts were not available for the full period of the contract.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the Energy Marketing and Generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of the Energy Marketing and Generation business segments.

The following table summarizes the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2014 and 2013, respectively:

	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, 2013	–	(66)	55	–	14	11	–	(52)	66
Changes attributable to:									
Market price changes on existing contracts	–	(13)	260	–	6	20	–	(7)	280
Market price changes on new contracts	–	3	–	–	131	(80)	–	134	(80)
Contracts settled	–	17	(1)	–	29	(48)	–	46	(49)
Net risk management assets (liabilities) at Dec. 31, 2014	**–**	**(59)**	**314**	**–**	**180**	**(97)**	**–**	**121**	**217**
Additional Level III information:									
Gains recognized in OCI			260			–			260
Total gains (losses) included in earnings before income taxes			1			(60)			(59)
Unrealized losses included in earnings before income taxes relating to net liabilities held at Dec. 31, 2014			–			(108)			(108)

	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, 2012	–	(63)	3	(1)	79	28	(1)	16	31
Changes attributable to:									
Market price changes on existing contracts	–	(18)	(6)	–	(21)	26	–	(39)	20
Market price changes on new contracts	–	5	58	–	(21)	(1)	–	(16)	57
Contracts settled	–	10	–	1	(51)	(14)	1	(41)	(14)
Transfers out of Level III	–	–	–	–	28	(28)	–	28	(28)
Net risk management assets (liabilities) at Dec. 31, 2013	–	(66)	55	–	14	11	–	(52)	66
Additional Level III information:									
Gains recognized in OCI			52			–			52
Total gains included in earnings before income taxes			–			25			25
Unrealized gains included in earnings before income taxes relating to net assets held at Dec. 31, 2013			–			11			11

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy marketing transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks. 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.

Other risk management assets and liabilities, with total net value of $115 million as at Dec. 31, 2014 (2013 – $27 million), are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

The fair value of financial liabilities measured at other than fair value is as follows:

	Fair value				Total
	Level I	Level II	Level III	Total	carrying value
Long-term debt[1] – Dec. 31, 2014	**–**	**4,091**	**–**	**4,091**	**3,918**
Long-term debt[1] – Dec. 31, 2013	–	4,367	–	4,367	4,262

1 *Includes current portion and excludes $64 million (Dec. 31, 2013 – $60 million) of debt measured and carried at fair value.*

The fair values of the Corporation's debentures and senior notes are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability.

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 inputs that are not readily observable. Refer to *Note 13(B)* for fair value Level III valuation techniques used. 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 (loss) 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 (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss), and a reconciliation of changes is as follows:

As at Dec. 31	**2014**	2013	2012
Unamortized net gain at beginning of year	**160**	5	4
New inception gains	**23**	156	3
Amortization recorded in net earnings during the year	**5**	(1)	(2)
Unamortized net gain at end of year	**188**	160	5

During 2013, the Corporation finalized a contract to sell power in the U.S. Pacific Northwest region. The contract was designated as an all-in-one cash flow hedge. As a result, the contract was recognized as a risk management asset at fair value. The fair value was classified as Level III, which resulted in the recognition of an inception gain. The inception gain was deferred and recorded as an offset to the risk management asset.

14. Risk Management Activities

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and liabilities are as follows:

As at Dec. 31, 2014

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	–	(2)	–	93	91
Long-term	–	257	–	(10)	247
Net commodity risk management assets	–	255	–	83	338
Other					
Current	–	56	–	(2)	54
Long-term	–	55	6	–	61
Net other risk management assets (liabilities)	–	111	6	(2)	115
Total net risk management assets	–	366	6	81	453

As at Dec. 31, 2013 *(Restated – see Note 3(B))*

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	–	(15)	–	30	15
Long-term	–	4	–	(5)	(1)
Net commodity risk management assets (liabilities)	–	(11)	–	25	14
Other					
Current	1	11	–	1	13
Long-term	–	7	7	–	14
Net other risk management assets	1	18	7	1	27
Total net risk management assets	1	7	7	26	41

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

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	**2014**				2013			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	578	608	(380)	(98)	385	285	(342)	(69)
Gross amounts set-off	(204)	(10)	204	10	(157)	–	156	1
Net amounts as presented in the Consolidated Statements of Financial Position	374	598	(176)	(88)	228	285	(186)	(68)

II. Hedges

a. *Net Investment Hedges*

i. Hedges of Foreign Operations

The Corporation's hedges of its net investment in foreign operations are comprised of U.S.-dollar-denominated long-term debt with a face value of U.S.$580 million (2013 – U.S.$850 million) and the following foreign currency forward contracts:

As at Dec. 31	2014			2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Currency Forward Contracts							
AUD235	**CAD221**	**–**	**2015**	AUD200	CAD188	1	2014
–	**–**	**–**	**–**	USD10	CAD11	–	2014

During 2014, following the divestiture of CE Gen *(see Note 4)*, the Corporation de-designated U.S.$180 million of U.S.-denominated debt from its net investment hedge of U.S. operations. Reclassification from AOCI of the cumulative translation adjustment of the disposed foreign operation and the related cumulative net investment hedge amounts have been included in the gain on disposition. In 2014, the Corporation also de-designated an additional U.S.$90 million of U.S.-denominated debt from its net investment hedge of other U.S. operations. This change did not impact earnings or AOCI in the period. Prospectively, the de-designated tranches of U.S.-denominated debt are being hedged with foreign currency derivative instruments.

During 2013, the Corporation de-designated $20 million of U.S.-dollar denominated debentures from its net investment hedges.

b. *Cash Flow Hedges*

i. Commodity Risk Management

The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	2014		2013	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**4,977**	**–**	5,977	–
Natural gas *(GJ)*	**963**	**32,113**	963	35,775
Oil *(gallons)*	**–**	**6,720**	–	4,116

During 2014, unrealized pre-tax gains of $3 million (2013 – $1 million, 2012 – nil) were released from AOCI and recognized in earnings due to hedge ineffectiveness for accounting purposes. All designated hedging relationships were effective as of Dec. 31, 2014.

During 2014, unrealized pre-tax gains of $2 million (2013 – nil, 2012 – $90 million gain) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings. The cash flow hedges were in respect of future power production expected to occur between 2012 and 2017. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using then current forward prices that changed between then and the time the contracts settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts would not change.

As at Dec. 31, 2014, cumulative gains of $3 million related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31	2014				2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign Exchange Forward Contracts – foreign-denominated receipts/expenditures							
CAD194	**USD180**	**16**	**2015–2018**	CAD220	USD205	2	2014–2018
AUD49	**JPY4,522**	**(1)**	**2015–2017**	–	–	–	–
USD4	**CAD4**	**–**	**2015**	USD4	CAD4	–	2014
CAD2	**EUR2**	**–**	**2015**	CAD3	EUR2	–	2014
Foreign Exchange Forward Contracts – foreign-denominated debt							
CAD59	**USD50**	**–**	**2015**	CAD52	USD50	2	2014
–	**–**	**–**	**–**	CAD106	USD100	1	2014
–	**–**	**–**	**–**	CAD310	USD300	9	2014
–	**–**	**–**	**–**	USD100	CAD107	–	2014
–	**–**	**–**	**–**	CAD22	USD20	–	2014
Cross-Currency Swaps – foreign-denominated debt							
CAD530	**USD500**	**50**	**2015**	CAD530	USD500	4	2015
CAD434	**USD400**	**28**	**2017**	–	–	–	–
CAD192	**USD180**	**18**	**2018**	–	–	–	–

iii. Effect of Cash Flow Hedges

The following tables summarize the pre-tax amounts recognized in and reclassified out of OCI related to cash flow hedges:

	Year ended Dec. 31, 2014				
	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) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
		Revenue	**24**	Revenue	**(3)**
Commodity contracts	**212**	Fuel and purchased power	**14**	Fuel and purchased power	**–**
Foreign exchange forwards on commodity contracts	**14**	Revenue	**(1)**	Revenue	**–**
Foreign exchange forwards on project hedges	**(1)**	Property, plant, and equipment	**–**	Foreign exchange (gain) loss	**–**
Foreign exchange forwards on U.S. debt	**(9)**	Foreign exchange (gain) loss	**6**	Foreign exchange (gain) loss	**–**
Cross-currency swaps	**89**	Foreign exchange (gain) loss	**(94)**	Foreign exchange (gain) loss	**–**
Forward starting interest rate swaps	**–**	Interest expense	**6**	Interest expense	**–**
OCI impact	**305**	**OCI impact**	**(45)**	**Net earnings impact**	**(3)**

Year ended Dec. 31, 2013					
	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) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		Revenue	17	Revenue	(2)
Commodity contracts	11	Fuel and purchased power	19	Fuel and purchased power	–
Foreign exchange forwards on commodity contracts	11	Revenue	2	Revenue	–
Foreign exchange forwards on project hedges	–	Property, plant, and equipment	2	Foreign exchange (gain) loss	–
Foreign exchange forwards on U.S. debt	33	Foreign exchange (gain) loss	(38)	Foreign exchange (gain) loss	–
Cross-currency swaps	33	Foreign exchange (gain) loss	(29)	Foreign exchange (gain) loss	–
Forward starting interest rate swaps	–	Interest expense	6	Interest expense	–
OCI impact	88	OCI impact	(21)	Net earnings impact	(2)

Year ended Dec. 31, 2012					
	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) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		Revenue	13	Revenue	(90)
Commodity contracts	36	Fuel and purchased power	2	Fuel and purchased power	–
Foreign exchange forwards on commodity contracts	(3)	Revenue	1	Revenue	–
Foreign exchange forwards on project hedges	(3)	Property, plant, and equipment	7	Foreign exchange (gain) loss	–
Foreign exchange forwards on U.S. debt	(20)	Foreign exchange (gain) loss	30	Foreign exchange (gain) loss	–
Cross-currency swaps	(6)	Foreign exchange (gain) loss	13	Foreign exchange (gain) loss	–
Forward starting interest rate swaps	(15)	Interest expense	2	Interest expense	3
OCI impact	(11)	OCI impact	68	Net earnings impact	(87)

Over the next 12 months, the Corporation estimates that $7 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (2013 – 6.65 per cent) to a floating interest rate based on the U.S. LIBOR rate using interest rate swaps as outlined below:

As at Dec. 31	2014		2013		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD50	**6**	**2018**	USD50	7	2018

Including the interest rate swaps above, 4 per cent of the Corporation's debt as at Dec. 31, 2014 is subject to floating interest rates (2013 – 21 per cent).

ii. Effects of Fair Value Hedges

The following table summarizes the pre-tax impact on the Consolidated Statements of Earnings (Loss) of fair value hedges, including any ineffective portion:

Year ended Dec. 31		**2014**	2013	2012
Derivatives in fair value hedging relationships	**Location of gain (loss) recognized in earnings**			
Interest rate contracts	Net interest expense	**(1)**	(2)	(16)
Long-term debt	Net interest expense	**1**	2	15
Earnings (loss) impact		**–**	–	(1)

III. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities 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 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. Commodity Risk Management

As at Dec. 31	2014		2013	
Type *(thousands)*	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**30,821**	**23,685**	34,741	24,456
Natural gas *(GJ)*	**156,898**	**198,969**	215,730	224,661
Emissions *(tonnes)*	**50**	**75**	70	70
Heating oil *(gallons)*	**–**	**–**	–	9,576

b. Other Non-Hedge Derivatives

As at Dec. 31	2014			2013			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts							
CAD264	**USD227**	**1**	**2015**	CAD91	USD85	1	2014
AUD63	**CAD61**	**1**	**2015**	–	–	–	–
AUD47	**USD40**	**3**	**2015-2016**	–	–	–	–
AUD10	**EUR7**	**–**	**2015**	–	–	–	–
Derivatives embedded in supplier contracts [1]							
USD40	**AUD47**	**(7)**	**2015-2016**	–	–	–	–
EUR7	**AUD10**	**–**	**2015**	–	–	–	–

1 *Result from payments that are not denominated in the functional currency of either party under a contract with a supplier.*

c. Total Return Swaps

The Corporation has certain compensation and deferred and restricted 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 applied. 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.

d. Effect of Non-Hedges

For the year ended Dec. 31, 2014, the Corporation recognized a net unrealized gain of $46 million (2013 – loss of $40 million, 2012 – loss of $123 million) related to commodity derivatives.

For the year ended Dec. 31, 2014, a gain of $10 million (2013 – gain of $8 million, 2012 – loss of $4 million) related to foreign exchange and other derivatives was recognized and is comprised of a net unrealized gain of $2 million (2013 – loss of $1 million, 2012 – gain of $1 million) and a net realized gain of $8 million (2013 – gain of $9 million, 2012 – loss of $5 million).

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.

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing 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 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, 2014 associated with the Corporation's proprietary trading activities was $5 million (2013 – $2 million, 2012 – $2 million).

ii. Commodity Price Risk – Generation

The Generation Segment utilizes various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Policy 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. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and 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, 2014 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $27 million (2013 – $42 million, 2012 – $5 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, 2014 associated with these transactions was $7 million (2013 – $11 million, 2012 – $9 million).

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, 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, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 15 basis point (2013 – 25 basis point, 2012 – 50 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2014**		2013		2012	
	Net earnings increase[1]	**OCI loss**[1]	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
Basis point change	**–**	**–**	2	–	4	–

1 This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the euro, the U.S. dollar, the Japanese yen, 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, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2013 – five cent, 2012 – five 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	**2014**		2013		2012	
Currency	**Net earnings increase (decrease)**[1]	**OCI gain**[1,2]	Net earnings increase[1]	OCI gain[1,2]	Net earnings decrease[1]	OCI gain[1,2]
USD	**4**	**5**	2	8	(2)	11
EUR	**–**	**–**	–	–	–	1
AUD	**(2)**	**–**	–	–	–	–
Total	**2**	**5**	2	8	(2)	12

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 designated as hedging instruments in net investment hedges has 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 Coal 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, 2014:

(Per cent)	**Investment grade**	**Non-investment grade**	**Total**
Accounts receivable	**89**	**11**	**100**
Risk management assets	**100**	**–**	**100**

The Corporation's maximum exposure to credit risk at Dec. 31, 2014, 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, including the fair value of open trading, net of any collateral held, at Dec. 31, 2014 was $29 million (2013 – $23 million).

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 strengthening its financial position and maintaining 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 Risk Management Committee, senior management, and the Board; and maintaining investment grade credit ratings.

A maturity analysis of the Corporation's net financial liabilities, as at Dec. 31, 2014, is as follows:

	2015	2016	2017	2018	2019	2020 and thereafter	Total
Accounts payable and accrued liabilities	481	–	–	–	–	–	481
Long-term debt[1]	738	29	466	878	402	1,472	3,985
Commodity risk management (assets) liabilities	(74)	(17)	(16)	(24)	(23)	(184)	(338)
Other risk management (assets) liabilities	(53)	(6)	(30)	(26)	–	–	(115)
Interest on long-term debt[2]	178	171	166	129	104	723	1,471
Dividends payable	55	–	–	–	–	–	55
Total	**1,325**	**177**	**586**	**957**	**483**	**2,011**	**5,539**

1 *Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature between 2016 and 2018.*
2 *Not recognized as a financial liability on the Consolidated Statements of Financial Position.*

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2014, the Corporation provided $25 million (2013 – $20 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, 2014, the Corporation received nil (2013 – nil) 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. 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 falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2014, the Corporation had posted collateral of $73 million (2013 – $94 million) in the form of letters of credit on derivative instruments primarily 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 $86 million (2013 – $88 million) of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2014.

IV. Gain on Sale of Collateral

During September 2012, the Corporation sold, for net proceeds of U.S.$33 million, its claim against MF Global Inc. pertaining to the return of U.S.$36 million of collateral that had been previously posted by the Corporation. As a result, a pre-tax gain of $15 million ($11 million after-tax) was realized in 2012.

In October 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. had not filed for bankruptcy in 2011 but, under the U.S. *Securities Investor Protection Act of 1970*, the Securities Investor Protection Corp. was overseeing a liquidation of the broker-dealer to return assets to customers. The Corporation's claim, filed during the first quarter of 2012, related primarily to the Corporation's collateral on foreign futures transactions.

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 Marketing, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2014	2013
Coal	**39**	53
Deferred stripping costs	**15**	13
Natural gas	**12**	5
Purchased emission credits	**5**	6
Total	**71**	77

The change in inventory is as follows:

Balance, Dec. 31, 2012	93
Net additions	7
Writedowns	(22)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2013	77
Net additions	14
Writedowns	(19)
Change in foreign exchange rates	(1)
Balance, Dec. 31, 2014	**71**

No inventory is pledged as security for liabilities.

16. Investments

Until February 2014, the Corporation's investments in joint ventures included investments in CE Gen, Wailuku, and CalEnergy LLC. See *Note 4* for further details regarding the divestitures.

The change in investments is as follows:

Balance, Dec. 31, 2012	172
Equity loss	(10)
Equity contribution	17
Change in foreign exchange rates	13
Balance, Dec. 31, 2013	192
Change in foreign exchange rates	4
Divestitures *(Note 4)*	(196)
Balance, Dec. 31, 2014	**-**

17. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of property, plant, and equipment is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2012	75	5,384	1,870	2,536	959	342	315	11,481
Additions	–	–	–	–	–	534	27	561
Additions – finance lease	–	–	–	–	33	–	–	33
Acquisition of Wyoming wind farm *(Note 4)*	–	–	–	78	–	–	1	79
Disposals	(1)	–	–	–	(3)	–	–	(4)
Impairment (charges) reversals *(Note 6)*	–	–	(1)	21	–	–	–	20
Revisions and additions to decommissioning and restoration costs	–	(3)	(7)	–	15	–	–	5
Retirement of assets	–	(159)	(13)	(13)	(17)	–	–	(202)
Change in foreign exchange rates	1	65	(26)	–	4	–	1	45
Transfers	2	357	35	235	75	(723)	25	6
As at Dec. 31, 2013	77	5,644	1,858	2,857	1,066	153	369	12,024
Additions	–	3	–	–	–	466	18	487
Additions – finance lease	–	–	–	–	58	–	–	58
Disposals	–	–	(34)	(1)	–	1	–	(34)
Impairment charges *(Note 6)*	–	–	–	(2)	–	–	–	(2)
Impairment reversals *(Note 6)*	–	–	9	2	–	–	–	11
Revisions and additions to decommissioning and restoration costs	–	11	4	(1)	10	–	–	24
Retirement of assets	–	(96)	(20)	(4)	(4)	–	–	(124)
Change in foreign exchange rates	2	92	4	7	4	(6)	3	106
Transfers	3	149	48	24	25	(273)	6	(18)
As at Dec. 31, 2014	**82**	**5,803**	**1,869**	**2,882**	**1,159**	**341**	**396**	**12,532**
Accumulated depreciation								
As at Dec. 31, 2012	–	2,510	874	532	442	–	79	4,437
Depreciation	–	263	99	91	57	–	13	523
Retirement of assets	–	(121)	(10)	(10)	(10)	–	–	(151)
Disposals	–	–	–	–	(3)	–	–	(3)
Change in foreign exchange rates	–	40	(12)	–	2	–	(2)	28
Impairment reversals *(Note 6)*	–	–	–	2	–	–	–	2
Transfers	–	–	(5)	–	–	–	–	(5)
As at Dec. 31, 2013	–	2,692	946	615	488	–	90	4,831
Depreciation	–	272	103	98	55	–	13	541
Retirement of assets	–	(84)	(19)	(1)	(2)	–	–	(106)
Disposals	–	–	(29)	–	–	–	–	(29)
Change in foreign exchange rates	–	61	4	1	3	–	–	69
Impairment reversals *(Note 6)*	–	–	3	–	–	–	–	3
Transfers	–	–	(15)	–	–	–	–	(15)
As at Dec. 31, 2014	**–**	**2,941**	**993**	**713**	**544**	**–**	**103**	**5,294**
Carrying amount								
As at Dec. 31, 2012	75	2,874	996	2,004	517	342	236	7,044
As at Dec. 31, 2013	77	2,952	912	2,242	578	153	279	7,193
As at Dec. 31, 2014	**82**	**2,862**	**876**	**2,169**	**615**	**341**	**293**	**7,238**

1 *Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventative, or planned maintenance.*

The Corporation capitalized $3 million of interest to PP&E in 2014 (2013 – $2 million) at a weighted average rate of 5.75 per cent (2013 – 5.46 per cent).

In 2014, operations began at a processing facility that the Corporation contracted a third party to construct and operate. The facility recovers fine coal out of pond slurry at the Corporation's Centralia mine as part of restoration activities. Recovered coal fines can be used as fuel at the coal plant. As a result of certain contractual provisions, the Corporation recognized a finance lease asset and an obligation in the amount of estimated minimum lease payments of U.S.$34 million, corresponding at inception to the penalties payable by the Corporation if it elects to terminate the agreement. Coal volume and slurry processing payments, net of the amortization and accretion of the financial lease obligation, are deemed to constitute contingent rents under the arrangement. Other finance lease additions are for mining equipment at the Highvale mine.

The carrying amount of total assets under finance leases as at Dec. 31, 2014 was $78 million (2013 – $29 million).

18. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions, as follows:

As at Dec. 31	2014	2013
Canadian Renewables and Alberta Merchant	**417**	417
Energy Marketing	**30**	30
U.S. Operations	**15**	13
Total goodwill	**462**	460

For purposes of the 2014 and 2013 annual goodwill impairment review, the Corporation determined the recoverable amount of the Canadian Renewables and Alberta Merchant group of CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

The key assumptions impacting the determination of fair value for the Canadian Renewables and Alberta Merchant group of CGUs are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities 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 facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Alberta Merchant electricity prices used in the 2014 models ranged between $31 to $276 per MWh during the forecast period (2013 – $41 to $263 per MWh). Discount rates used for the goodwill impairment calculation in 2014 ranged from 5.4 per cent to 6.9 per cent (2013 – 4.9 per cent to 7.1 per cent). No reasonably possible change in the assumptions would have resulted in an impairment of goodwill.

No impairment of goodwill arose in 2014 or 2013.

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 Dec. 31, 2012	158	133	173	40	504
Additions	20	–	–	29	49
Acquisition of Wyoming wind farm *(Note 4)*	–	7	13	–	20
Retirements	–	(10)	–	–	(10)
Transfers	–	50	–	(47)	3
As at Dec. 31, 2013	178	180	186	22	566
Additions	–	8	–	26	34
Retirements	–	(3)	–	–	(3)
Change in foreign exchange rates	–	3	–	–	3
Transfers	–	18	–	(14)	4
As at Dec. 31, 2014	**178**	**206**	**186**	**34**	**604**
Accumulated amortization					
As at Dec. 31, 2012	100	93	27	–	220
Amortization	4	21	8	–	33
Retirements	–	(10)	–	–	(10)
As at Dec. 31, 2013	104	104	35	–	243
Amortization	2	21	8	–	31
Retirements	–	(3)	–	–	(3)
Change in foreign exchange rates	–	2	–	–	2
As at Dec. 31, 2014	**106**	**124**	**43**	**–**	**273**
Carrying amount					
As at Dec. 31, 2012	58	40	146	40	284
As at Dec. 31, 2013	74	76	151	22	323
As at Dec. 31, 2014	**72**	**82**	**143**	**34**	**331**

20. Other Assets

The components of other assets are as follows:

As at Dec. 31	**2014**	2013
Deferred licence fees	**16**	18
Project development costs	**29**	36
Deferred service costs	**18**	19
Long-term prepaids, receivables, and other	**29**	18
Keephills Unit 3 transmission deposit	**6**	6
Total other assets	**98**	97

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are 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 seven years to 2021, as long as certain performance criteria are met.

21. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2012	262	8	42	312
Liabilities incurred	4	–	29	33
Liabilities settled	(24)	(5)	(2)	(31)
Accretion	17	–	1	18
Revisions in estimated cash flows	16	–	2	18
Revisions in discount rates	(12)	–	–	(12)
Reversals[1]	–	(3)	(11)	(14)
Acquisition of Wyoming wind farm *(Note 4)*	3	–	–	3
Change in foreign exchange rates	4	–	1	5
Balance, Dec. 31, 2013	270	–	62	332
Liabilities incurred	3	–	19	22
Liabilities settled	(16)	–	(31)	(47)
Accretion	18	–	–	18
Revisions in estimated cash flows	–	–	3	3
Revisions in discount rates	24	–	–	24
Reversals	–	–	(2)	(2)
Change in foreign exchange rates	6	–	–	6
Balance, Dec. 31, 2014	**305**	**–**	**51**	**356**

1 The reversal of other provisions includes Sundance Units 1 and 2 and Sundance Unit 3 provisions that were reversed as a result of the conclusions of the respective arbitration decisions in 2012.

	Decommissioning and restoration	Restructuring	Other	Total
Balance, Dec. 31, 2013	270	–	62	332
Current portion	22	–	5	27
Non-current portion	248	–	57	305
Balance, Dec. 31, 2014	**305**	**–**	**51**	**356**
Current portion	**28**	**–**	**6**	**34**
Non-current portion	**277**	**–**	**45**	**322**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines 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 2015 and 2072. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2014, the Corporation had provided a surety bond in the amount of U.S.$140 million (2013 – U.S.$136 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2014, the Corporation had provided letters of credit in the amount of $115 million (2013 – $115 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Restructuring Provisions

On Oct. 30, 2012, the Corporation announced a restructuring of resources as part of its ongoing strategy to continuously improve operational excellence and accelerate the growth of the company. Approximately 165 positions were eliminated. In 2012, a provision and a related pre-tax restructuring expense of $13 million were recognized. On completion of the restructuring in 2013, the balance of the provision in the amount of $3 million was reversed.

C. Other Provisions

Other provisions include an amount related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2018 and 2020.

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

22. Long-Term Debt and Finance Lease Obligations

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31		2014			2013	
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**96**	**96**	**2.8%**	852	852	2.6%
Debentures	**1,043**	**1,051**	**6.1%**	1,269	1,251	6.1%
Senior notes[3]	**2,444**	**2,436**	**4.9%**	1,797	1,809	5.6%
Non-recourse[4]	**380**	**383**	**5.9%**	376	380	5.9%
Other	**19**	**19**	**5.9%**	28	28	6.3%
	3,982	**3,985**		4,322	4,320	
Finance lease obligations	**74**			25		
	4,056			4,347		
Less: current portion of long-term debt	**(738)**			(209)		
Less: current portion of finance lease obligations	**(13)**			(8)		
Total current long-term debt and finance lease obligations	**(751)**			(217)		
Total long-term debt and finance lease obligations	**3,305**			4,130		

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. Foreign-denominated amounts included in the balance are nil at Dec. 31, 2014 and U.S.$300 million at Dec. 31, 2013.

3 U.S. face value at Dec. 31, 2014 – U.S.$2.1 billion (Dec. 31, 2013 – U.S.$1.7 billion).

4 Includes U.S.$20 million at Dec. 31, 2014 (Dec. 31, 2013 – U.S.$20 million).

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 bilateral 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 Corporation's four-year revolving $1.5 billion committed syndicated credit facility, last renewed in June 2014, matures in 2018. The U.S.$300 million bilateral credit facility has a four-year term to 2017. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, U.S. LIBOR, or U.S. base rate – in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities, which mature in 2016.

Of the $2.1 billion (2013 – $2.1 billion) of committed credit facilities, $1.6 billion (2013 – $0.9 billion) is not drawn, and is available as of Dec. 31, 2014, subject to customary borrowing conditions. In addition to the $1.6 billion available under the credit facilities, TransAlta also has $43 million of available cash and cash equivalents.

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2019 to 2030. During the second quarter of 2014, the Corporation's $200 million 6.45 per cent medium-term notes matured and were paid out. During 2013, the Corporation issued $400 million of senior unsecured medium-term notes that carry a coupon rate of 5.00 per cent, payable semi-annually, at an issue price equal to 99.516 per cent of the principal amount of the notes.

Senior notes bear interest at rates ranging from 1.90 per cent to 6.65 per cent and have maturity dates ranging from 2015 to 2040. In June 2014, the Corporation issued U.S.$400 million of senior notes due in 2017 that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes. A total of U.S.$580 million of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations. During 2013, the Corporation's U.S.$300 million 5.75 per cent senior notes matured and were paid out.

Non-recourse debt consists of debentures that have maturity dates ranging from 2015 to 2018 and bear interest at rates ranging from 5.3 per cent to 7.3 per cent.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal. Notes payable for the Windsor plant matured and were paid out in November 2014.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2014, the Corporation was in compliance with all debt covenants.

B. Restrictions

Debentures of $344 million issued by the Corporation's CHD subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewables assets.

C. Principal Repayments

	2015	2016	2017	2018	2019	2020 and thereafter	Total
Principal repayments[1]	738	29	466	878	402	1,472	**3,985**

1 *Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to mature in 2015 and 2017.*

D. Finance Lease Obligations

Amounts payable for mining assets and other finance leases are as follows:

As at Dec. 31	2014		2013	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	**16**	**16**	9	9
Second to fifth years inclusive	**43**	**37**	18	16
More than five years	**30**	**21**	–	–
	89	**74**	27	25
Less: interest costs	**15**	**–**	2	–
Total finance lease obligations	**74**	**74**	25	25
Current portion of finance lease obligations	**13**		8	
Long-term portion of finance lease obligations	**61**		17	
	74		25	

E. 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 under these contracts 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, 2014 was $396 million (2013 – $370 million) with no (2013 – nil) amounts exercised by third parties under these arrangements.

23. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2014	2013
Defined benefit obligation *(Note 28)*	**226**	200
Deferred coal revenues	**58**	52
Long-term incentive accruals *(Note 27)*	**13**	16
Other	**52**	72
Total	**349**	340

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint operation partner for future coal deliveries. 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.

Other includes $12 million (2013 – $13 million) relating to a reimbursement received for costs of the New Richmond terminal station, which is being amortized into revenue over the term of the related PPA, and nil (2013 – $28 million) relating to the California claim *(see Note 8)*.

24. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. Changes in the common shares issued are as follows:

As at Dec. 31	2014		2013	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**268.2**	**2,916**	254.7	2,730
Issued under the dividend reinvestment and share purchase plan	**6.8**	**85**	13.5	186
	275.0	**3,001**	268.2	2,916
Amounts receivable under Employee Share Purchase Plan	**–**	**(2)**	–	(3)
Issued and outstanding, end of year	**275.0**	**2,999**	268.2	2,913

B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Board 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 Shareholder Rights Plan was originally approved in 1992, and has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and was last approved on April 23, 2013.

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. Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan (the "Plan")

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan provided 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 Corporation suspended the Premium Dividend™ Component of the Plan following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remain effective in accordance with their current terms.

On Jan. 1, 2015, 1.9 million common shares were issued for dividends reinvested.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

D. Earnings per Share

Year ended Dec. 31	**2014**	2013	2012
Net earnings (loss) attributable to common shareholders	**141**	(71)	(615)
Basic and diluted weighted average number of common shares outstanding	**273**	264	235
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.52**	(0.27)	(2.62)

E. Dividends

On Jan. 23, 2015, the Corporation declared a quarterly dividend of $0.18 per common share, payable on April 1, 2015.

Dividends per common share declared in 2014 were $0.72 (2013 and 2012 – $1.16).

25. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	**2014**		2013	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	**12.0**	**293**	12.0	293
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	–	–
Issued and outstanding, end of year	**38.6**	**942**	32.0	781

The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, they are also:

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada three-month Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2014, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	First Rate Reset Date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	1.15	March 31, 2016	2.03	B
B	Floating	–	–	2.03	A
C	Fixed	1.15	June 30, 2017	3.10	D
D	Floating	–	–	3.10	C
E	Fixed	1.25	Sept. 30, 2017	3.65	F
F	Floating	–	–	3.65	E
G[1]	Fixed	1.325	Sept. 30, 2019	3.80	H
H	Floating	–	–	3.80	G

1 On Aug. 15, 2014, the Corporation completed a public offering of 6.6 million Series G preferred shares for gross proceeds of $165 million (net proceeds of $161 million after issue costs, net of tax effects).

B. Dividends

The following table summarizes the preferred share dividends declared in 2014, 2013, and 2012:

Series	**2014**	2013	2012
A	**14**	14	14
C[1]	**13**	13	14
E	**11**	11	4
G[2]	**3**	–	–
Total for the year	**41**	38	32

1 2012 includes dividends of $0.0969 per share ($1 million in total) for the period from Nov. 29, 2011 to Dec. 31, 2011.
2 2014 includes dividends for the period from issuance on Aug. 15, 2014 to Dec. 31, 2014.

On Jan. 23, 2015, the Corporation declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable March 31, 2015.

26. Accumulated Other Comprehensive Income (Loss)

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2014	2013
Currency translation adjustment		
Opening balance, Jan. 1	**(36)**	(38)
Gains on translating net assets of foreign operations, net of reclassifications to net earnings	**68**	37
Losses on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(51)**	(35)
Balance, Dec. 31	**(19)**	(36)
Cash flow hedges		
Opening balance, Jan. 1	**4**	(37)
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[2]	**169**	41
Balance, Dec. 31	**173**	4
Employee future benefits		
Opening balance, Jan. 1	**(30)**	(61)
Net actuarial gains (losses) on defined benefit plans, net of tax[3]	**(20)**	31
Balance, Dec. 31	**(50)**	(30)
Accumulated other comprehensive income (loss)	**104**	(62)

1 *Net of income tax recovery of 9 for the year ended Dec. 31, 2014 (2013 – 5 recovery).*
2 *Net of income tax expense of 94 for the year ended Dec. 31, 2014 (2013 – 12 expense).*
3 *Net of income tax recovery of 7 for the year ended Dec. 31, 2014 (2013 – 11 expense).*

27. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of three performance measures: growth in funds from operation per share, growth in free cash flow per share, and growth in the Corporation's total shareholder return relative to the S&P/TSX Composite Index. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued at the end of each reporting period using the closing price of the Corporation's common shares on the Toronto Stock Exchange ("TSX").

The pre-tax compensation expense related to PSUs and RSUs was $8 million (2013 – $6 million, 2012 – $1 million), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares.

DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the Director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was less than $1 million in each of the years ended Dec. 31 2014, 2013, and 2012.

C. Stock Option Plans

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 on the TSX as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

Options granted under the stock option 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. In Canada, this plan is offered to all full-time and part-time employees below the level of manager. In the U.S., this plan is offered to all full-time and part-time employees. In Australia, options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. This plan is offered to all full-time and part-time employees in Australia below the level of manager.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2014 are outlined below:

	Options outstanding			Options exercisable	
Range of exercise prices *($ per share)*	**Number outstanding at Dec. 31, 2014** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*	**Number exercisable at Dec. 31, 2014** *(millions)*	**Weighted average exercise price** *($ per share)*
16.80-24.07	0.8	3.8	21.37	0.8	21.37
31.97-40.12	0.6	3.1	33.03	0.6	33.03
16.80-40.12	**1.4**	**4.5**	**26.20**	**1.4**	**26.20**

No stock options were granted in 2014, 2013, or 2012. The pre-tax expense recognized arising from equity-settled share-based payment transactions was nil (2013 – nil, 2012 – $1 million).

D. Performance Share Ownership Plan ("PSOP")

Under the terms of the PSOP, participants received grants that, after three years, made 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 granting of PSOP units was discontinued following the 2012-2014 grant and the plan was terminated on Dec. 31, 2014.

In 2014, pre-tax PSOP compensation expense recovery was $7 million (2013 – $6 million recovery, 2012 – $3 million expense), which is included in operations, maintenance, and administration expense. In 2014, no common shares (2013 – nil, 2012 – 55,418 common shares at $15.12 per share) were issued.

E. 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 purchases 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, 2014, amounts receivable from employees under the plan totalled $2 million (2013 – $3 million).

28. Employee Future Benefits

A. Description

The Corporation sponsors 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. Except for the Highvale pension plans acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 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, 2014 and Jan. 1, 2014, respectively. The latest actuarial valuation for accounting purposes of the Highvale pension plan was at Dec. 31, 2013. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2014.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The last actuarial valuations for funding purposes of the Canadian registered plans were completed in early 2014 with an effective date of Dec. 31, 2013. The last actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2014.

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 $64 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 through its other post-employment benefits plans. The latest actuarial valuation for accounting purposes of the Canadian and U.S. plans was as at Dec. 31, 2013 and Jan. 1, 2014, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2014.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution, and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**6**	**2**	**2**	**10**
Administration expenses	**2**	**-**	**-**	**2**
Interest cost on defined benefit obligation	**23**	**4**	**1**	**28**
Interest on plan assets	**(18)**	**-**	**-**	**(18)**
Defined benefit expense	**13**	**6**	**3**	**22**
Defined contribution expense	**18**	**-**	**-**	**18**
Net expense	**31**	**6**	**3**	**40**

Year ended Dec. 31, 2013	Registered	Supplemental	Other	Total
Current service cost	6	3	2	11
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(15)	-	-	(15)
Defined benefit expense	14	6	3	23
Defined contribution expense	18	-	-	18
Net expense	32	6	3	41

Year ended Dec. 31, 2012	Registered	Supplemental	Other	Total
Current service cost	2	2	1	5
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	18	3	2	23
Interest on plan assets	(13)	–	–	(13)
Defined benefit expense	9	5	3	17
Defined contribution expense	20	–	–	20
Net expense	29	5	3	37

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

As at Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**427**	**8**	**–**	**435**
Present value of defined benefit obligation	**(565)**	**(86)**	**(30)**	**(681)**
Funded status – plan deficit	**(138)**	**(78)**	**(30)**	**(246)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(14)**	**(5)**	**(1)**	**(20)**
Other long-term liabilities	**(124)**	**(73)**	**(29)**	**(226)**
Total amount recognized	**(138)**	**(78)**	**(30)**	**(246)**

As at Dec. 31, 2013	Registered	Supplemental	Other	Total
Fair value of plan assets	394	7	–	401
Present value of defined benefit obligation	(517)	(74)	(27)	(618)
Funded status – plan deficit	(123)	(67)	(27)	(217)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(12)	(4)	(1)	(17)
Other long-term liabilities	(111)	(63)	(26)	(200)
Total amount recognized	(123)	(67)	(27)	(217)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
Fair value of plan assets as at Dec. 31, 2012	294	5	–	299
Acquisition of Highvale pension plan	72	–	–	72
Interest on plan assets	15	–	–	15
Net return on plan assets	29	–	–	29
Contributions	18	7	3	28
Benefits paid	(33)	(5)	(3)	(41)
Administration expenses	(2)	–	–	(2)
Effect of translation on U.S. plans	1	–	–	1
Fair value of plan assets as at Dec. 31, 2013	**394**	**7**	**–**	**401**
Interest on plan assets	**18**	**–**	**–**	**18**
Net return on plan assets	**33**	**–**	**–**	**33**
Contributions	**14**	**5**	**1**	**20**
Benefits paid	**(33)**	**(4)**	**(1)**	**(38)**
Administration expenses	**(2)**	**–**	**–**	**(2)**
Effect of translation on U.S. plans	**3**	**–**	**–**	**3**
Fair value of plan assets as at Dec. 31, 2014	**427**	**8**	**–**	**435**

The fair value of the Corporation's defined benefit plan assets by major category is as follows:

Year ended Dec. 31, 2014	Level I	Level II	Level III	Total
Equity securities				
Canadian	**–**	**102**	**–**	**102**
U.S.	**–**	**49**	**–**	**49**
International	**–**	**70**	**–**	**70**
Private	**–**	**–**	**5**	**5**
Bonds				
AAA	**–**	**57**	**–**	**57**
AA	**1**	**54**	**–**	**55**
A	**1**	**64**	**–**	**65**
BBB	**–**	**16**	**–**	**16**
Below BBB	**–**	**1**	**–**	**1**
Money market and cash and cash equivalents	**4**	**11**	**–**	**15**
Total	**6**	**424**	**5**	**435**

Year ended Dec. 31, 2013	Level I	Level II	Level III	Total
Equity securities				
Canadian	–	99	–	99
U.S.	–	47	–	47
International	–	70	–	70
Private	–	–	6	6
Bonds				
AAA	–	46	–	46
AA	1	58	–	59
A	1	45	–	46
BBB	–	13	–	13
Below BBB	–	2	–	2
Money market and cash and cash equivalents	3	10	–	13
Total	5	390	6	401

Plan assets do not include any common shares of the Corporation at Dec. 31, 2014 and Dec. 31, 2013. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2014 (2013 – $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2012	424	77	34	535
Acquisition of Highvale pension plan	99	–	–	99
Current service cost	6	3	2	11
Interest cost	21	3	1	25
Benefits paid	(33)	(5)	(3)	(41)
Actuarial loss arising from demographic assumptions	20	3	–	23
Actuarial gain arising from financial assumptions	(28)	(5)	(3)	(36)
Actuarial (gain) loss arising from experience adjustments	6	(2)	(5)	(1)
Effect of translation on U.S. plans	2	–	1	3
Present value of defined benefit obligation as at Dec. 31, 2013	517	74	27	618
Current service cost	**6**	**2**	**2**	**10**
Interest cost	**23**	**4**	**1**	**28**
Benefits paid	**(33)**	**(4)**	**(1)**	**(38)**
Actuarial (gain) loss arising from demographic assumptions	**4**	**–**	**(2)**	**2**
Actuarial loss arising from financial assumptions	**50**	**8**	**3**	**61**
Actuarial (gain) loss arising from experience adjustments	**(5)**	**2**	**(1)**	**(4)**
Effect of translation on U.S. plans	**3**	**–**	**1**	**4**
Present value of defined benefit obligation as at Dec. 31, 2014	**565**	**86**	**30**	**681**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2014 is 13.7 years.

F. Contributions

The expected employer contributions for 2015 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	14	5	2	21

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2014			As at Dec. 31, 2013		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.8**	**3.8**	**3.8**	4.6	4.5	4.5
Rate of compensation increase	**3.0**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.6**[1]	-	-	7.7[3]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**5.0**	-	-	5.0
Benefit cost for the year						
Discount rate	**4.6**	**4.5**	**4.5**	4.1	4.0	3.9
Rate of compensation increase	**3.0**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.8**[2]	-	-	7.4[4]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**5.0**	-	-	3.5

1 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2019-2020 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

2 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

3 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35 per cent per year to 5 per cent in 2024 for Canada.*

4 *Post- and pre-65 rates; decreasing gradually to 5 per cent by 2016-2019 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.5 per cent per year to 5 per cent in 2018 for Canada.*

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2014	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**73**	**13**	**2**	**4**	**1**
1% increase in the salary scale	**8**	**11**	**-**	**-**	**-**
1% increase in the health care cost trend rate	**-**	**-**	**2**	**-**	**1**
10% improvement in mortality rates	**17**	**2**	**-**	**1**	**-**

29. Joint Arrangements

Joint arrangements at Dec. 31, 2014 included the following:

Joint operations	Fuel type	Ownership (per cent)	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
TransAlta MidAmerican Partnership	Gas	50	Strategic partnership to develop, build, and operate new natural gas-fuelled electricity generation projects in Canada
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Joint venture to build and operate natural gas pipeline in Western Australia to transport natural gas to the Corporation's Solomon power station
McBride Lake	Renewables	50	Wind generation facilities in Alberta operated by TransAlta
Soderglen	Renewables	50	Wind generation facilities in Alberta operated by TransAlta
Pingston	Renewables	50	Hydro facility in British Columbia operated by TransAlta

Joint ventures	Business activity	Ownership (per cent)	Description
TAMA Transmission LP	Transmission	50	Strategic partnership to develop and operate transmission projects in Alberta

30. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2014	2013	2012
(Use) source:			
Accounts receivable	**59**	125	(22)
Prepaid expenses	**(1)**	(7)	3
Income taxes receivable	**1**	(14)	(10)
Inventory	**7**	15	(3)
Accounts payable, accrued liabilities, and provisions	**8**	(51)	(8)
Income taxes payable	**(1)**	6	(16)
Change in non-cash operating working capital	**73**	74	(56)

31. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2014	2013	Increase/ (decrease)
Long-term debt[1]	**4,056**	4,347	**(291)**
Equity			
Common shares	**2,999**	2,913	**86**
Preferred shares	**942**	781	**161**
Contributed surplus	**9**	9	**–**
Deficit	**(770)**	(735)	**(35)**
Accumulated other comprehensive income (loss)	**104**	(62)	**166**
Non-controlling interests	**594**	517	**77**
Less: available cash and cash equivalents[2]	**(43)**	(42)	**(1)**
Less: fair value assets of hedging instruments on long-term debt[3]	**(96)**	(16)	**(80)**
Total capital	**7,795**	7,712	**83**

1 *Includes finance lease obligations, amounts under credit facilities, and current portion of long-term debt.*

2 *The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available, and used to facilitate repayment of debt.*

3 *The Corporation includes the fair value of hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.*

TransAlta's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2013 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 interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios, and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

As at Dec. 31	2014	2013[1]	Target
Adjusted comparable funds from operations to adjusted interest coverage *(times)*	**3.8**	3.7	4 to 5
Adjusted comparable funds from operations to adjusted net debt *(%)*	**16.9**	15.2	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization *(times)*	**4.2**	4.6	3 to 4

1 *Prior year figures have been restated to conform to the current year's presentation. To align more closely to credit rating agencies' calculation of key ratios, the Corporation now uses debt balances at period-end, includes finance lease obligations as debt and finance lease interest in interest, and treats 50 per cent of dividends paid on preferred shares as interest and 50 per cent of issued preferred shares as debt. In prior periods, the Corporation used average debt and did not treat preferred shares as debt or preferred dividends as interest.*

Adjusted comparable funds from operations ("FFO") to interest coverage is calculated as comparable FFO plus interest on debt (net of interest income and capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares less interest income. Comparable FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. Adjusted comparable FFO to interest coverage increased compared to 2013. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted comparable FFO to net debt is calculated as cash flow from operating activities before changes in working capital less 50 per cent of dividends paid on preferred shares divided by total debt plus 50 per cent of issued preferred shares less cash and cash equivalents. Adjusted comparable FFO to net debt increased in 2014 compared to 2013 due to lower debt levels in 2014. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA") is calculated as net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents) divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation, and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. Adjusted net debt to comparable EBITDA in 2014 increased compared to 2013. The Corporation's goal is to maintain this ratio in a range of three to four times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2014, the Corporation took several steps to strengthen its financial position and reduce debt, using the proceeds from the sale of CE Gen, Blackrock, CalEnergy, and Wailuku *(see Note 4)*, the secondary offering of TransAlta Renewables common shares *(see Note 11)*, and the offering of preferred shares *(see Note 25)* to pay down credit facility borrowings, repay the scheduled maturity of a debenture, and increase liquidity. During 2013, the Corporation also used the approximate $221 million in gross proceeds from the initial public offering of TransAlta Renewables common shares *(see Note 11)* to pay down debt. The Corporation utilizes the proceeds from dividends reinvested under the Dividend Reinvestment and Share Purchase Plan as a continued source of equity.

Management 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 property, plant, and equipment expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, and Invest in Property, Plant, and Equipment

For the year ended Dec. 31, 2014 and 2013, net cash outflows, after cash dividends paid on common shares, property, plant, and equipment additions, and business acquisitions, are summarized below:

Year ended Dec. 31	2014	2013	Increase (decrease)
Cash flow from operating activities	**796**	765	**31**
Dividends paid on common shares	**(140)**	(116)	**(24)**
Dividends paid on preferred shares	**(41)**	(38)	**(3)**
Distributions paid to subsidiaries' non-controlling interests	**(84)**	(55)	**(29)**
Property, plant, and equipment expenditures	**(487)**	(561)	**74**
Acquisition of Wyoming wind farm	**–**	(109)	**109**
Inflow (outflow)	**44**	(114)	**158**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2014, $1.6 billion (2013 – $0.9 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, 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 2014, the Corporation completed a secondary offering of the common shares of TransAlta Renewables for gross proceeds to the Corporation of approximately $136 million; issued 6.6 million Series G preferred shares for gross proceeds of $165 million; issued U.S.$400 million of senior notes; and repaid $200 million of medium-term notes that matured.

During 2013, the Corporation issued $400 million of senior unsecured medium-term notes, received $221 million in gross proceeds from the initial public offering of TransAlta Renewables, and repaid U.S.$300 senior notes on maturity.

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. 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 marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	70.3	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, the Executive Vice Presidents, and the Vice President, Gas and Renewables, all who report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	2014	2013	2012
Total compensation	**13**	15	12
Comprised of:			
Short-term employee benefits	**8**	7	8
Post-employment benefits	**2**	2	1
Other long-term benefits	**–**	1	1
Termination benefits	**–**	2	–
Share-based payments	**3**	3	2

33. Commitments

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has entered into a number of fixed purchase and transportation contracts, transmission and electricity purchase agreements, coal supply and mining agreements, long-term service agreements, and agreements related to growth and major projects either directly or through its interests in joint ventures. Approximate future payments under these agreements are as follows:

	Natural gas, transportation, and other purchase contracts	Transmission and power purchase agreements	Coal supply and mining agreements	Long-term service agreements	Non-cancellable operating leases	Growth	Total
2015	43	12	159	119	11	207	551
2016	29	9	137	120	10	50	355
2017	13	3	44	105	8	175	348
2018	12	4	45	33	8	8	110
2019	7	2	46	31	8	–	94
2020 and thereafter	101	6	605	172	54	–	938
Total	**205**	**36**	**1,036**	**580**	**99**	**440**	**2,396**

A. Natural Gas, Transportation, and Other Purchase Contracts

Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other fixed price purchase contracts relate to commitments for services at certain facilities.

B. Transmission and Power Purchase Agreements

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

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2024.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities, and turbines at various wind facilities.

E. Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment.

During the year ended Dec. 31, 2014, $10 million (2013 – $10 million, 2012 – $13 million) was recognized as an expense 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.

F. Growth

Commitments for growth relate to the South Hedland power station, the Australian natural gas pipeline to the Solomon power station, and transmission upgrades.

G. TransAlta Energy Bill Commitments

As part of the Bill and Memorandum of Agreement ("MoA") signed into law in the State of Washington, the Corporation has committed to fund U.S.$55 million over the life of the Centralia coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in certain circumstances this funding or part thereof would no longer be required.

H. 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 includes: 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.

34. 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. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

35. Segment Disclosures

A. Description of Reportable Segments

The Corporation has three reportable segments as described in *Note 1*.

A portion of operations, maintenance, and administration costs incurred in the Energy Marketing Segment and the Corporate Segment are allocated to other segments based on an estimate of operating expenses and a percentage of resources dedicated to providing support and services. Segment operations, maintenance, and administration costs are comprised of expenses net of intersegment allocations. In prior years, the Energy Marketing intersegment charge and recovery was presented as a distinct line item as a component of operating income (loss). Comparative figures have been reclassified to conform to the current year's presentation.

B. Reported Segment Earnings and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**2,515**	**108**	**-**	**2,623**
Fuel and purchased power	**1,092**	**-**	**-**	**1,092**
Gross margin	**1,423**	**108**	**-**	**1,531**
Operations, maintenance, and administration	**447**	**32**	**63**	**542**
Depreciation and amortization	**512**	**-**	**26**	**538**
Asset impairment reversals	**(6)**	**-**	**-**	**(6)**
Taxes, other than income taxes	**28**	**-**	**1**	**29**
Net other operating (income) losses	**(19)**	**5**	**-**	**(14)**
Net operating income (loss)	**461**	**71**	**(90)**	**442**
Finance lease income	**49**	**-**	**-**	**49**
Gain on sale of assets	**2**	**-**	**-**	**2**
Net interest expense				**(254)**
Earnings before income taxes				**239**

Year ended Dec. 31, 2013 *(Restated – see Note 3(B))*	Generation	Energy Marketing	Corporate	Total
Revenues	2,213	79	–	2,292
Fuel and purchased power	948	–	–	948
Gross margin	1,265	79	–	1,344
Operations, maintenance, and administration	432	18	66	516
Depreciation and amortization	501	1	23	525
Asset impairment charges (reversals)	(18)	–	–	(18)
Restructuring provision	(2)	–	(1)	(3)
Taxes, other than income taxes	26	–	1	27
Net other operating losses	46	56	–	102
Operating income (loss)	280	4	(89)	195
Finance lease income	46	–	–	46
Equity loss	(10)	–	–	(10)
Gain on sale of assets	–	–	12	12
Net interest expense				(256)
Foreign exchange gain				1
Loss before income taxes				(12)

Year ended Dec. 31, 2012 *(Restated – see Note 3(B))*	Generation	Energy Marketing	Corporate	Total
Revenues	2,207	3	–	2,210
Fuel and purchased power	797	–	–	797
Gross margin	1,410	3	–	1,413
Operations, maintenance, and administration	401	16	82	499
Depreciation and amortization	489	–	20	509
Asset impairment charges	324	–	–	324
Restructuring provision	5	–	8	13
Taxes, other than income taxes	27	–	1	28
Net other operating losses	254	–	–	254
Operating losses	(90)	(13)	(111)	(214)
Finance lease income	16	–	–	16
Equity loss	(15)	–	–	(15)
Gain on sale of assets	3	–	–	3
Gain on sale of collateral	–	15	–	15
Net interest expense				(242)
Other income				1
Foreign exchange loss				(9)
Loss before income taxes				(445)

Included in the Generation Segment revenue is $21 million (2013 – $22 million, 2012 – $23 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

Total rental income, including contingent rent, related to certain PPAs and other long-term contracts that meet the criteria of operating leases, is included in the Generation Segment revenues, and was $219 million for the year ended Dec. 31, 2014 (2013 – $208 million, 2012 – $188 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	**432**	**30**	**–**	**462**
Total segment assets	**9,274**	**246**	**313**	**9,833**

As at Dec. 31, 2013	Generation[1]	Energy Marketing	Corporate	Total
Goodwill	430	30	–	460
Total segment assets *(Restated – see Note 3(B))*	9,093	244	287	9,624

1 *Total Generation Segment assets include $192 million related to investments in joint arrangements accounted for using the equity method.*

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2014	**Generation**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:				
Property, plant, and equipment	**481**	**1**	**5**	**487**
Intangible assets	**9**	**8**	**17**	**34**

Year ended Dec. 31, 2013	Generation	Energy Marketing	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	554	–	7	561
Intangible assets	5	6	21	32

Year ended Dec. 31, 2012	Generation	Energy Marketing	Corporate	Total
Additions to non-current assets:				
Property, plant, and equipment	684	–	19	703
Intangible assets	7	1	31	39

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

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

Year ended Dec. 31	**2014**	2013	2012
Depreciation and amortization expense on the Consolidated Statements of Earnings	**538**	525	509
Depreciation included in fuel and purchased power *(Note 5)*	**56**	58	41
Gain on disposal of property, plant, and equipment	**1**	2	14
Depreciation and amortization on the Consolidated Statements of Cash Flows	**595**	585	564

C. Geographic Information

I. Revenues

Year ended Dec. 31	**2014**	2013	2012
Canada	**1,989**	1,898	1,789
U.S.	**516**	287	300
Australia	**118**	107	121
Total revenue	**2,623**	2,292	2,210

II. Non-Current Assets

	Property, plant, and equipment		**Intangible assets**		**Other assets**		**Goodwill**	
As at Dec. 31	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Canada	**6,422**	6,538	**296**	295	**66**	57	**417**	417
U.S.	**552**	517	**25**	24	**14**	21	**45**	43
Australia	**264**	138	**10**	4	**18**	19	**–**	–
Total	**7,238**	7,193	**331**	323	**98**	97	**462**	460

D. Significant Customer

During the year ended Dec. 31, 2014, sales to one customer in the Generation Segment represented 12 per cent of the Corporations's total revenue.

36. Subsequent Events

A. Restructuring

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at the Corporation's Canadian Coal operations, resulting in the elimination of positions. Costs associated with the initiative are expected to total $10 million.

B. Bond Issuance

On Feb. 11, 2015, the Corporation and its partner issued bonds secured by their jointly owned Pingston facility. The Corporation's share of gross proceeds was $45 million. The bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent. Excess proceeds, net of transaction costs, are to be used for general corporate purposes.