# TransAlta Corporation

# Consolidated Financial Statements

*December 31, 2013*

# 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

**Brett M. Gellner**
Chief Financial and Chief Investment Officer

February 20, 2014

# Management's Annual Report on Internal Control over Financial Reporting

## To the Shareholders of TransAlta Corporation

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

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

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

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

TransAlta Corporation proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations and equity accounts for the CE Generation, LLC ("CE Gen") and Wailuku River Hydroelectric, L.P. ("Wailuku") joint ventures in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint 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 2013 consolidated financial statements of TransAlta Corporation included $886 million and $857 million of total and net assets, respectively, as of December 31, 2013, and $199 million and $38 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, 2013, 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, 2013, 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

**Brett M. Gellner**
Chief Financial and Chief Investment Officer

February 20, 2014

# Independent Auditors' Report of 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, 2013, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria) (1992 framework). The Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the corporation; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the corporation's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the CE Gen, Sheerness, Wailuku, and Genesee Unit 3 joint arrangements, which are included in the 2013 consolidated financial statements of the Corporation and constituted $886 million and $857 million of total and net assets, respectively, as of December 31, 2013, and $199 million and $38 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the CE Gen, Sheerness, Wailuku, and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2013 and 2012, and the related 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, 2013 and our report dated February 20, 2014, expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 20, 2014

# Independent Auditors' Report of Registered Public Accounting Firm

## To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation as of December 31, 2013 and 2012, and the related 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, 2013. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of TransAlta Corporation at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the years in three-year period ended December 31, 2013, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

As discussed in Note 3 to the consolidated financial statements, the Corporation changed its method of accounting for employee benefits and accounting for stripping costs in the production phase of a surface mine as a result of the adoption of IAS 19, "Employee Benefits" and IFRIC 20, "Stripping Costs in the Production Phase of a Surface Mine" effective January 1, 2013, which included the disclosure of a statement of financial position as of January 1, 2012.

We also have 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, 2013, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 20, 2014 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada

February 20, 2014

# Consolidated Statements of Earnings (Loss)

| Year ended Dec. 31 *(in millions of Canadian dollars except where noted)* | **2013** | 2012 *(Restated)** | 2011 *(Restated)** |
|---|---|---|---|
| Revenues *(Note 12)* | **2,292** | 2,210 | 2,618 |
| Fuel and purchased power *(Note 11)* | **926** | 753 | 895 |
| **Gross margin** | **1,366** | 1,457 | 1,723 |
| Operations, maintenance, and administration *(Note 11)* | **516** | 499 | 552 |
| Depreciation and amortization | **525** | 509 | 482 |
| Asset impairment charges (reversals) *(Note 13)* | **(18)** | 324 | 17 |
| Inventory writedown *(Note 22)* | **22** | 44 | – |
| Restructuring provision *(Note 28)* | **(3)** | 13 | – |
| Taxes, other than income taxes | **27** | 28 | 27 |
| **Operating income** | **297** | 40 | 645 |
| Finance lease income *(Notes 8 and 12)* | **46** | 16 | 8 |
| Equity income (loss) *(Note 14)* | **(10)** | (15) | 14 |
| California claim *(Note 5)* | **(56)** | – | – |
| Sundance Units 1 and 2 return to service *(Note 6)* | **(25)** | (254) | – |
| Gain on sale of assets *(Note 8)* | **12** | 3 | 16 |
| Other income | **–** | 1 | 2 |
| Foreign exchange gain (loss) | **1** | (9) | (3) |
| Loss on assumption of pension obligations *(Note 7)* | **(29)** | – | – |
| Gain on sale of (reserve on) collateral *(Note 9)* | **–** | 15 | (18) |
| Insurance recovery *(Note 10)* | **8** | – | – |
| Net interest expense *(Note 15)* | **(256)** | (242) | (215) |
| **Earnings (loss) before income taxes** | **(12)** | (445) | 449 |
| Income tax expense (recovery) *(Note 16)* | **(8)** | 102 | 106 |
| **Net earnings (loss)** | **(4)** | (547) | 343 |
| **Net earnings (loss) attributable to:** | | | |
| TransAlta shareholders | **(33)** | (584) | 305 |
| Non-controlling interests *(Note 18)* | **29** | 37 | 38 |
| | **(4)** | (547) | 343 |
| **Net earnings (loss) attributable to TransAlta shareholders** | **(33)** | (584) | 305 |
| Preferred share dividends *(Note 32)* | **38** | 31 | 15 |
| **Net earnings (loss) attributable to common shareholders** | **(71)** | (615) | 290 |
| **Weighted average number of common shares outstanding in the year** *(millions)* | **264** | 235 | 222 |
| | | | |
| **Net earnings (loss) per share attributable to common shareholders, basic and diluted** *(Note 31)* | **(0.27)** | (2.62) | 1.31 |

** See Note 3 for prior period restatements.*

*See accompanying notes.*

# Consolidated Statements of Comprehensive Income (Loss)

| Year ended Dec. 31 *(in millions of Canadian dollars)* | **2013** | 2012 *(Restated)** | 2011 *(Restated)** |
|---|---|---|---|
| **Net earnings (loss)** | **(4)** | (547) | 343 |
| **Other comprehensive income (loss)** | | | |
| Net actuarial gains (losses) on defined benefit plans, net of tax[1] | **31** | (23) | (21) |
| Losses on derivatives designated as cash flow hedges, net of tax[2] | **–** | (2) | (4) |
| Reclassification of 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** | **32** | (20) | (25) |
| Gains (losses) on translating net assets of foreign operations | **37** | (23) | 32 |
| Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[4] | **(35)** | 13 | (33) |
| Gains (losses) on derivatives designated as cash flow hedges, net of tax[5] | **76** | (12) | (99) |
| Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[6] | **(24)** | (6) | (177) |
| **Total items that will be reclassified subsequently to net earnings** | **54** | (28) | (277) |
| **Other comprehensive income (loss)** | **86** | (48) | (302) |
| **Total comprehensive income (loss)** | **82** | (595) | 41 |
| **Total comprehensive income (loss) attributable to:** | | | |
| Common shareholders | **41** | (626) | 23 |
| Non-controlling interests | **41** | 31 | 18 |
| | **82** | (595) | 41 |

* *See Note 3 for prior period restatements.*

1 *Net of income tax expense of 11 for the year ended Dec. 31, 2013 (2012 – 8 recovery, 2011 – 7 recovery).*

2 *Net of income tax of nil for the year ended Dec. 31, 2013 (2012 – 1 recovery, 2011 – 2 recovery).*

3 *Net of income tax recovery of 1 for the year ended Dec. 31, 2013 (2012 – 2 recovery, 2011 – nil).*

4 *Net of income tax recovery of 5 for the year ended Dec. 31, 2013 (2012 – 2 expense, 2011 – 5 recovery).*

5 *Net of income tax expense of 12 for the year ended Dec. 31, 2013 (2012 – 4 expense, 2011 – 5 recovery).*

6 *Net of income tax expense of 1 for the year ended Dec. 31, 2013 (2012 – 20 expense, 2011 – 94 expense).*

*See accompanying notes.*

# Consolidated Statements of Financial Position

| *(in millions of Canadian dollars)* | **Dec. 31, 2013** | Dec. 31, 2012 *(Restated)** | Jan. 1, 2012 *(Restated)** |
|---|---|---|---|
| Cash and cash equivalents *(Note 21)* | **42** | 27 | 49 |
| Accounts receivable *(Notes 17, 19, and 20)* | **473** | 597 | 541 |
| Current portion of finance lease receivable *(Notes 12 and 19)* | **3** | 2 | 3 |
| Collateral paid *(Notes 19 and 20)* | **20** | 19 | 45 |
| Prepaid expenses | **12** | 7 | 8 |
| Risk management assets *(Notes 19 and 20)* | **112** | 201 | 391 |
| Inventory *(Note 22)* | **77** | 93 | 92 |
| Income taxes receivable *(Note 23)* | **8** | 4 | 2 |
| | **747** | 950 | 1,131 |
| Investments *(Note 14)* | **192** | 172 | 193 |
| Long-term receivable *(Note 9)* | **–** | – | 18 |
| Long-term portion of finance lease receivable *(Notes 12 and 19)* | **377** | 357 | 42 |
| Property, plant, and equipment *(Notes 24 and 42)* | | | |
| Cost | **12,024** | 11,481 | 11,386 |
| Accumulated depreciation | **(4,831)** | (4,437) | (4,115) |
| | **7,193** | 7,044 | 7,271 |
| Goodwill *(Notes 25 and 42)* | **460** | 447 | 447 |
| Intangible assets *(Notes 26 and 42)* | **323** | 284 | 276 |
| Deferred income tax assets *(Note 16)* | **118** | 90 | 213 |
| Risk management assets *(Notes 19 and 20)* | **276** | 69 | 99 |
| Other assets *(Notes 27 and 42)* | **97** | 90 | 90 |
| **Total assets** | **9,783** | 9,503 | 9,780 |
| Accounts payable and accrued liabilities *(Notes 19 and 20)* | **447** | 495 | 463 |
| Current portion of decommissioning and other provisions *(Note 28)* | **16** | 33 | 99 |
| Collateral received *(Notes 19 and 20)* | **–** | 2 | 16 |
| Risk management liabilities *(Notes 19 and 20)* | **84** | 167 | 208 |
| Income taxes payable | **3** | 7 | 22 |
| Dividends payable *(Notes 19, 20, and 31)* | **85** | 75 | 67 |
| Current portion of finance lease obligation *(Notes 8, 12, and 19)* | **8** | – | – |
| Current portion of long-term debt *(Notes 19, 20, and 29)* | **209** | 607 | 316 |
| | **852** | 1,386 | 1,191 |
| Long-term debt *(Notes 19, 20, and 29)* | **4,113** | 3,610 | 3,721 |
| Finance lease obligation *(Notes 8, 12, and 19)* | **17** | – | – |
| Decommissioning and other provisions *(Note 28)* | **316** | 279 | 283 |
| Deferred income tax liabilities *(Note 16)* | **459** | 473 | 530 |
| Risk management liabilities *(Notes 19 and 20)* | **263** | 106 | 142 |
| Deferred credits and other long-term liabilities *(Note 30)* | **340** | 301 | 281 |
| Equity | | | |
| Common shares *(Note 31)* | **2,913** | 2,726 | 2,273 |
| Preferred shares *(Note 32)* | **781** | 781 | 562 |
| Contributed surplus | **9** | 9 | 9 |
| Retained earnings (deficit) | **(735)** | (362) | 524 |
| Accumulated other comprehensive loss *(Note 33)* | **(62)** | (136) | (94) |
| **Equity attributable to shareholders** | **2,906** | 3,018 | 3,274 |
| Non-controlling interests *(Note 18)* | **517** | 330 | 358 |
| **Total equity** | **3,423** | 3,348 | 3,632 |
| **Total liabilities and equity** | **9,783** | 9,503 | 9,780 |

** See Note 3 for prior period restatements.*

Commitments *(Note 40)*

Contingencies *(Note 41)*

Subsequent events *(Note 43)*

*See accompanying notes.*

Gordon D Giffin          Karen E Maidment

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 | Retained earnings (deficit) *(Restated)** | Accumulated other comprehensive income (loss)[1] *(Restated)** | Attributable to shareholders | Attributable to non-controlling interests | Total |
|---|---|---|---|---|---|---|---|---|
| Balance, Dec. 31, 2011 | 2,273 | 562 | 9 | 524 | (94) | 3,274 | 358 | 3,632 |
| Net earnings (loss) | – | – | – | (584) | – | (584) | 37 | (547) |
| Other comprehensive income (loss): | | | | | | | | |
| Net losses on translating net assets of foreign operations, net of hedges and of tax | – | – | – | – | (10) | (10) | – | (10) |
| Net losses on derivatives designated as cash flow hedges, net of tax | – | – | – | – | (9) | (9) | (6) | (15) |
| Net actuarial gains on defined benefits plans, net of tax | – | – | – | – | (23) | (23) | – | (23) |
| Total comprehensive income | | | | (584) | (42) | (626) | 31 | (595) |
| Common share dividends | – | – | – | (271) | – | (271) | – | (271) |
| Preferred share dividends | – | – | – | (31) | – | (31) | – | (31) |
| Distributions paid to non-controlling interests | – | – | – | – | – | – | (59) | (59) |
| Common shares issued | 453 | – | – | – | – | 453 | – | 453 |
| Preferred shares issued | – | 219 | – | – | – | 219 | – | 219 |
| 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 4)* | **–** | **–** | **–** | **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** |

* *See Note 3 for prior period restatements.*

1 *Refer to Note 33 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)* | **2013** | 2012 *(Restated)** | 2011 *(Restated)** |
|---|---|---|---|
| **Operating activities** | | | |
| Net earnings (loss) | **(4)** | (547) | 343 |
| Depreciation and amortization *(Note 42)* | **585** | 564 | 532 |
| Gain on sale of assets *(Note 8)* | **(12)** | (3) | (16) |
| California claim *(Note 5)* | **28** | – | – |
| Accretion of provisions *(Note 28)* | **18** | 17 | 19 |
| Decommissioning and restoration costs settled *(Note 28)* | **(24)** | (34) | (33) |
| Deferred income tax expense (recovery) *(Note 16)* | **(47)** | 89 | 80 |
| Unrealized (gain) loss from risk management activities | **76** | 99 | (175) |
| Unrealized foreign exchange (gain) loss | **(1)** | 5 | 3 |
| Provisions | **11** | 11 | 22 |
| Asset impairment charges (reversals) *(Note 13)* | **(18)** | 324 | 17 |
| Sundance Units 1 and 2 return to service *(Notes 6 and 13)* | **25** | 43 | – |
| Reserve on collateral *(Note 9)* | **–** | – | 18 |
| Equity loss, net of distributions received *(Note 14)* | **10** | 14 | 1 |
| Other non-cash items | **44** | (6) | (2) |
| Cash flow from operations before changes in working capital | **691** | 576 | 809 |
| Change in non-cash operating working capital balances *(Note 37)* | **74** | (56) | (119) |
| **Cash flow from operating activities** | **765** | 520 | 690 |
| **Investing activities** | | | |
| Additions to property, plant, and equipment *(Notes 24 and 42)* | **(561)** | (703) | (453) |
| Additions to intangibles *(Notes 26 and 42)* | **(32)** | (39) | (30) |
| Acquisition of finance lease *(Note 8)* | **–** | (312) | – |
| Addition to equity investments | **(17)** | – | – |
| Proceeds on sale of property, plant, and equipment | **14** | 3 | 12 |
| Proceeds on sale of facilities and development projects *(Note 8)* | **–** | 3 | 40 |
| Acquisition of the remaining 50% of the Taylor Hydro joint venture *(Note 8)* | **–** | – | (7) |
| Resolution of certain outstanding tax matters *(Notes 16 and 23)* | **2** | 9 | 3 |
| Realized gains (losses) on financial instruments | **14** | (13) | (12) |
| Net decrease in collateral received from counterparties | **(1)** | (13) | (109) |
| Net (increase) decrease in collateral paid to counterparties | **–** | 24 | (56) |
| Decrease in finance lease receivable | **1** | 3 | 3 |
| Acquisition of Wyoming wind farm *(Note 8)* | **(109)** | – | – |
| Other | **15** | (8) | (3) |
| Change in non-cash investing working capital balances | **(29)** | (2) | 4 |
| **Cash flow used in investing activities** | **(703)** | (1,048) | (608) |
| **Financing activities** | | | |
| Net increase (decrease) in borrowings under credit facilities *(Note 29)* | **(119)** | 152 | 155 |
| Repayment of long-term debt *(Note 29)* | **(328)** | (314) | (234) |
| Issuance of long-term debt *(Note 29)* | **398** | 388 | – |
| Dividends paid on common shares *(Note 31)* | **(116)** | (104) | (191) |
| Dividends paid on preferred shares *(Note 32)* | **(38)** | (32) | (15) |
| Net proceeds on issuance of common shares *(Note 31)* | **–** | 293 | 2 |
| Net proceeds on issuance of preferred shares *(Note 32)* | **–** | 217 | 267 |
| Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)* | **207** | – | – |
| Realized gains (losses) on financial instruments | **15** | (31) | 9 |
| Distributions paid to subsidiaries' non-controlling interests *(Note 18)* | **(55)** | (59) | (61) |
| Decrease in finance lease obligation | **(9)** | – | – |
| Other | **(2)** | (6) | (2) |
| **Cash flow from (used in) financing activities** | **(47)** | 504 | (70) |
| **Cash flow from (used in) operating, investing, and financing activities** | **15** | (24) | 12 |
| **Effect of translation on foreign currency cash** | **–** | 2 | 2 |
| **Increase (decrease) in cash and cash equivalents** | **15** | (22) | 14 |
| **Cash and cash equivalents, beginning of year** | **27** | 49 | 35 |
| **Cash and cash equivalents, end of year** | **42** | 27 | 49 |
| Cash income taxes paid (recovered) | **46** | 30 | (1) |
| Cash interest paid | **240** | 234 | 197 |

* *See Note 3 for prior period restatements.*

*See accompanying notes.*

# Notes to Consolidated Financial Statements

*(Tabular amounts in millions of Canadian dollars, except as otherwise noted)*

## 1. Corporate Information

### A. Description of the Business

TransAlta Corporation ("TransAlta" or "the Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992 after TransAlta Utilities Corporation became a subsidiary.

The three reportable segments of the Corporation are as follows:

**I. Generation**

The Generation Segment owns and operates hydro, wind, geothermal, natural gas- and coal-fired facilities, and related mining operations in Canada, the United States ("U.S."), and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Starting in 2013, electricity sales generated 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 on a net basis.

**II. Energy Trading**

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

Energy Trading manages available generating capacity as well as the fuel and transmission needs of the Generation Segment by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of all of these activities are included in the Generation Segment.

**III. Corporate**

The Corporate Segment provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support to the Generation and Energy Trading segments.

### 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 of Directors on Feb. 20, 2014.

### C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiary so as to obtain benefits from its activities, generally indicated by ownership of, directly or indirectly, more than one-half of the voting rights. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

# 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 reliably measured. 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.

Electricity sales generated by the Corporation's Commercial and Industrial group that are sourced from the Corporation's production are recognized on a net basis.

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).

Trading activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in the Consolidated Statements of Earnings (Loss). 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 the 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 derecognized when the contractual rights to receive cash flows expire. Financial liabilities are removed from the Consolidated Statements of Financial Position when the obligation is discharged, cancelled, or expired.

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, 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 trading 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 assets and liabilities on the Consolidated Statements of Financial Position or to specific firm commitments or highly probable anticipated transactions.

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If the above hedge criteria are not met 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 derivatives' 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 cost and net realizable value. Cost is determined using the weighted average cost method.

The cost of internally produced coal inventory is determined using absorption costing, which is defined as the sum of all applicable expenditures and charges directly incurred in bringing inventory to its existing condition and location. Available coal inventory tends to increase during the second and third quarters as a result of favourable weather conditions and lower electricity production as maintenance is performed. Due to the limited number of processing steps incurred in mining coal and preparing it for consumption and the relatively low value on a per-unit basis, management does not distinguish between work in process and coal available for consumption. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

### II. Energy Trading

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

## 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 of the asset is included in the income statement 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:

| | |
|---|---|
| Thermal generation | 3-50 years |
| Gas generation | 2-30 years |
| Renewable generation | 3-60 years |
| Mining property and equipment | 4-50 years |
| Capital spares and other | 2-50 years |

TransAlta capitalizes borrowing costs on capital invested in projects under construction (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 of the intangible asset, and its probable future economic benefits, are demonstrated. Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any. Amortization 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 with indefinite useful lives are not amortized, but are tested for impairment annually.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, coal rights, software, and intangibles under development. Estimated useful lives of intangible assets are as follows:

| | |
|---|---|
| Software | 2-7 years |
| Power contracts | 1-30 years |

## I. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Corporation reviews the net carrying amount of PP&E and finite life intangible assets to determine whether there is any indication that an impairment loss may exist.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating a 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 businesses, the market, and the 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. Information regarding the 2013 determination of CGUs for asset impairment testing can be found in Note 13. Recoverable amount is the higher of an asset's fair value less costs to sell and its value in use. Fair value is the amount at which an item could be bought or sold in a current transaction between willing parties. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. When the recoverable amount is based on value in use, the Corporation bases its impairment on detailed cash flow budgets and forecasts over the asset's useful life. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the 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 to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Information regarding the 2013 determination of CGUs for goodwill impairment testing can be found in Note 25. To test for impairment, the recoverable amount of the CGUs to which the goodwill relates is compared to the carrying amount of the CGUs. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

## 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 the carrying amount of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

## 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 may arise from the Corporation's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the Corporation has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, re-measured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. At each reporting date, the Corporation determines the present value of the provision using 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 equity-settled stock option awards using the fair value method. Compensation expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled share-based payment award that vests in instalments is accounted for as a separate award with its own distinct fair value measurement.

Compensation costs associated with awards under the Performance Share Ownership Plan ("PSOP") are accrued based on the fair value of each award, the service period completed, and the number of equivalent common shares eligible employees and directors have earned each period-end, which is based upon the percentile ranking of the total shareholder return of the Corporation's common shares in comparison to the total shareholder returns of companies comprising the comparative group.

For share-based payments earned under cash-settled phantom stock option plans, a liability, and corresponding compensation cost, is recognized at each period-end, until final settlement, based on the fair value of each award and the service period completed.

## 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, these 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 to sell. Any impairment is recognized in net earnings. Depreciation ceases when an asset 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 (i.e. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance 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.

## 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 are 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. Objective evidence could include, for example, such factors as significant financial difficulty of the investee, or information about significant changes with an adverse effect that have taken place in the technological, market, economic, or legal environment in which the investee operates, which may indicate that the cost of the investment may not be recovered. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs to sell.

## 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. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of consolidated financial statements requires management to make judgments, estimates, and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses, and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation, and regulations.

In the process of applying the Corporation's accounting policies, 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 or CGU to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less cost to sell and its value in use. An assessment is also made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. In determining fair value less costs to sell, information about third-party transactions for similar assets is used and if none are available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs to sell or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs, and other related cash inflows or outflows over the life of the plants, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations, and transmission capacity or constraints for the remaining life of the plant. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material. Key assumptions used in determining the 2012 recoverable amount of the Centralia Coal plant and Sundance Units 1 and 2 are further explained in Note 13. Information regarding the 2013 determination of CGUs for asset and goodwill impairment testing can be found in Notes 13 and 25.

### II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant 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 must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amount recognized for deferred income tax assets and liabilities.

**IV. Financial Instruments and Derivatives**

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 19. 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. 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.

**VI. Provisions for Decommissioning and Restoration Activities**

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 28. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

**VII. Useful Life of PP&E**

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate.

**VIII. Employee Future Benefits**

The Corporation provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for 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.

**IX. Other Provisions**

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized.

# 3. Accounting Changes

## A. Adoption of New or Amended IFRS

On Jan. 1, 2013, the Corporation adopted the following new accounting standards that were previously issued by the IASB:

### I. IFRS 10 *Consolidated Financial Statements*

IFRS 10 replaces the parts of IAS 27 *Consolidated and Separate Financial Statements* that deal with consolidated financial statements and Standing Interpretations Committee ("SIC") Interpretation 12 *Consolidation – Special Purpose Entities*. IFRS 10 defines the principle of control, establishes control as the basis for determining when entities are to be consolidated, and provides guidance on how to apply the principle of control to identify whether an investor controls an investee. Under IFRS 10, an investor controls an investee when it has all of the following: (i) power over the investee; (ii) exposure, or rights, to variable returns from the investee; and (iii) the ability to affect those returns.

IFRS 10 was applied retrospectively by the Corporation by reassessing whether, on Jan. 1, 2013, the Corporation had control of all of its previously consolidated entities. As a result of adopting IFRS 10, no changes arose in the entities controlled and consolidated by the Corporation.

### II. IFRS 11 *Joint Arrangements*

IFRS 11 replaces IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers.* IFRS 11 provides for a principles-based approach to the accounting for joint arrangements that requires an entity to recognize its contractual rights and obligations arising from its involvement in joint arrangements. A joint arrangement is an arrangement in which two or more parties have joint control. Under IFRS 11, joint arrangements are classified as either a joint operation or a joint venture, whereas under IAS 31, they were classified as a jointly controlled asset, jointly controlled operation, or a jointly controlled entity. IFRS 11 requires the use of the equity method of accounting for interests in joint ventures, whereas IAS 31 permitted a choice of the equity method or proportionate consolidation for jointly controlled entities. Under IFRS 11, for joint operations, each party recognizes its respective share of the assets, liabilities, revenues, and expenses of the arrangement, generally resulting in proportionate consolidation accounting.

IFRS 11 was applied retrospectively by the Corporation by reassessing the type of, and accounting for, each joint arrangement in existence at Jan. 1, 2013. No significant impacts resulted.

### III. IFRS 12 *Disclosure of Interests in Other Entities*

IFRS 12 contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint arrangements, associates, and consolidated and unconsolidated structured entities (special purpose entities). The objective of IFRS 12 is that an entity should disclose information that helps financial statement users evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial statements. Disclosures arising from the adoption of IFRS 12 can be found in Notes 14, 18, and 29.

### IV. IFRS 13 *Fair Value Measurement*

IFRS 13 establishes a single source of guidance for all fair value measurements required by other IFRS, clarifies the definition of fair value, and enhances disclosures about fair value measurements. IFRS 13 applies when other IFRS require or permit fair value measurements or disclosures. IFRS 13 specifies how an entity should measure fair value and disclose fair value information. It does not specify when an entity should measure an asset, a liability, or its own equity instrument at fair value. The Corporation's adoption of IFRS 13, prospectively on Jan. 1, 2013, did not have a material financial impact upon the consolidated financial position or results of operations; however, certain new or enhanced disclosures are required and can be found in Note 19.

### V. IAS 1 *Presentation of Financial Statements*

Amendments to IAS 1 *Presentation of Financial Statements* issued in June 2011 were intended to improve the consistency and clarity of the presentation of items of comprehensive income by requiring that items presented in OCI be grouped on the basis of whether they are subsequently reclassified from OCI to net earnings or not. The Consolidated Statements of Comprehensive Income (Loss) have been reorganized to comply with the required groupings.

**VI. IAS 19 *Employee Benefits***

Amendments to IAS 19 Employee Benefits are intended to improve the recognition, presentation, and disclosure of defined benefit plans. The amendments require the recognition of changes in defined benefit obligations and in fair value of plan assets when they occur, thus eliminating the "corridor approach" previously permitted. All actuarial gains and losses must be recognized immediately through OCI and the net pension liability or asset recognized at the full amount of the plan deficit or surplus.

Additional changes relate to the presentation, into three components, of changes in defined benefit obligations and plan assets: service cost and net interest cost is recognized in net earnings and remeasurements are recognized in OCI. The net interest cost introduced in these amendments removes the concept of expected return on plan assets that was previously recognized in net earnings.

The Corporation calculates the net interest cost for its defined benefit plans by applying the discount rate at the beginning of the reporting period to the net defined benefit liability at the beginning of the reporting period. An expected return on plan assets is no longer calculated and recognized as part of pension expense. The elimination of the corridor method had no impact as the Corporation has, since the adoption of IFRS, recognized actuarial gains and losses in OCI in the period in which they occurred.

On adoption, the Corporation applied the amendments retrospectively. The impacts as at Dec. 31, 2012 and Jan. 1, 2012, respectively, were an increase in the cumulative prior periods' pre-tax pension expense of $17 million and $11 million ($12 million and $8 million after-tax, respectively), as a result of the application of the net interest cost requirements.

For the year ended Dec. 31, 2012, Operations, maintenance, and administration expense increased by $4 million (2011 – $7 million) as a result of increased pension expense and net after-tax actuarial losses on defined benefit plans as reported in OCI decreased by $3 million (2011 – $5 million).

**VII. Interpretation 20 *Stripping Costs in the Production Phase of a Surface Mine ("IFRIC 20")***

IFRIC 20 clarifies the requirements for accounting for stripping costs in the production phase of a surface mine. Stripping costs are costs associated with the process of removing waste from a surface mine in order to gain access to mineral ore deposits. The Interpretation clarifies when production stripping should lead to the recognition of an asset and how that asset should be measured, both initially and in subsequent periods.

The Corporation recognizes a stripping activity asset for its Highvale mine 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.

As required by the transitional provision of IFRIC 20, the Interpretation was applied by the Corporation to production stripping costs incurred on or after Jan. 1, 2011, which will be the earliest comparative period presented within the Corporation's annual financial statements for the year ended Dec. 31, 2013, which resulted in adjustments to the 2012 earnings. The impacts on the Consolidated Statements of Financial Position as at Dec. 31, 2012 were to recognize $9 million in costs as a stripping activity asset, increase coal inventory by $2 million, both classified within inventory, increase deferred income tax liabilities by $3 million, and decrease retained deficit by $8 million. The impacts on the Consolidated Statements of Financial Position as at Jan. 1, 2012 were to recognize $9 million in costs as a stripping activity asset, decrease coal inventory by $2 million, both classified within inventory, increase deferred income tax liabilities by $2 million, and increase retained earnings by $5 million.

The impact of this change in accounting policy on the Consolidated Statements of Earnings (Loss) for the year ended Dec. 31, 2012 was a reduction of $4 million in fuel and purchased power (2011 – $7 million).

Basic and diluted net earnings per share attributable to common shareholders for 2012 decreased by $0.01 (2011 – nil) as a result of IAS 19 and IFRIC 20 impacts.

**VIII. IFRS 7 *Financial Instruments: Disclosures***

Amendments to IFRS 7 include disclosures about all recognized financial instruments that are set-off in accordance with IAS 32. The amendments also require disclosure of information about recognized financial instruments subject to enforceable master netting arrangements and similar agreements even if they are not set-off under IAS 32. The resulting disclosures can be found in Note 20.

**IX. Annual Improvements 2009-2011**

In May 2012, the IASB issued a collection of necessary, non-urgent amendments to several IFRS resulting from its annual improvements process. The amendments, as applicable, have been applied by the Corporation on Jan. 1, 2013. None of the amendments, which are generally technical and narrow in scope, had a material financial impact upon the consolidated financial position or results of operations.

## B. Current Accounting Changes

**Change in Estimates – Useful Lives**

During 2013, management completed a comprehensive review of the estimated useful lives of our hydro assets, having regard for, among other things, our economic life cycle maintenance program and the existing condition of the assets. As a result, depreciation was reduced by $5 million for the year ended Dec. 31, 2013 and is expected to be reduced by $5 million annually thereafter.

## C. Prior Year Accounting Changes

**Change in Estimates – Useful Lives**

As a result of amendments to Canadian federal regulations requiring that coal-fired plants be shut down after 50 years of operation, the Corporation reviewed the useful lives of its Alberta coal-fired generating facilities and related coal mining assets and where permitted under the regulations, extended the useful lives to the maximum of 50 years. The previous draft regulations proposed shutdown after 45 years. As a result, depreciation expense was reduced by $12 million for the year ended Dec. 31, 2012 compared to 2011.

## D. 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.

## E. Future Accounting Changes

New or amended applicable accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation, are as follows:

**IFRS 9 *Financial Instruments***

In November 2009, the IASB issued IFRS 9 *Financial Instruments*, which replaced the classification and measurement requirements in IAS 39 *Financial Instruments: Recognition and Measurement* for financial assets. Financial assets must be classified and measured at either amortized cost or 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.

In October 2010, the IASB issued additions to IFRS 9 regarding financial liabilities. The new requirements address the problem of volatility in net earnings arising from an issuer choosing to measure a liability at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

In November 2013, the IASB issued amendments to IFRS 9 that introduce a new general hedge accounting model intended to be simpler and more closely focus on how an entity manages its risks. Additional amendments to IFRS 9 allow a reporting entity to present changes in its own credit risk associated with liabilities designated at fair value through profit or loss in OCI.

The IASB also removed the Jan. 1, 2015 mandatory effective date from IFRS 9. The IASB will decide on a new effective date when the entire IFRS 9 project is closer to completion. Entities may still early-adopt the finalized and issued provisions of IFRS 9.

The Corporation does not expect that any material impacts will result from these standards; however, the Corporation continues to assess the impact of adopting these amendments on the consolidated financial statements.

**II. IAS 36 *Impairment of Assets (Recoverable Amount Disclosures)***

In May 2013, the IASB issued amendments to the disclosure requirements of IAS 36 *Impairment of Assets*. The amendments clarify that the recoverable amount of an asset or CGU is to be disclosed only in periods in which an impairment loss has been recognized or reversed. Additional disclosures regarding the level of the IFRS 13 fair value hierarchy and information about valuation techniques and key assumptions are required, in certain circumstances, when an impairment loss or reversal has been recognized and the recoverable amount is based on fair value less costs of disposal. The amended disclosure requirements apply retrospectively to annual reporting periods beginning on or after Jan. 1, 2014.

**III. IAS 32 *Offsetting Financial Assets and Liabilities***

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation*. The amendments are intended to clarify certain aspects of the existing guidance on offsetting financial assets and financial liabilities due to the diversity in application of the requirements on offsetting and are effective for annual periods beginning on or after Jan. 1, 2014. The Corporation is currently assessing the impact of adopting the IAS 32 amendments on the consolidated financial statements.

# 4. TransAlta Renewables Inc.

On May 28, 2013 the Corporation formed a new subsidiary, TransAlta Renewables Inc. ("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. As a result, any loans outstanding or transactions between the Corporation and TransAlta Renewables are eliminated on consolidation in the Corporation's financial statements.

## A. Transfer of Generating Assets

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. As consideration for the transfer, the Corporation received: i) 66.7 million common shares of TransAlta Renewables valued at $10.00 per share for total share consideration of $667 million; ii) a Closing Note receivable in the amount of $187 million; iii) a Short Term Note receivable in the amount of $250 million; iv) an Acquisition Note receivable in the amount of $30 million; and v) an Amortizing Loan receivable in the amount of $200 million.

## B. Initial Public Offering of Common Shares

On July 31, 2013, TransAlta Renewables filed a final prospectus to qualify the distribution of 20.0 million of its common shares, to be issued pursuant to the terms of an underwriting agreement at a price of $10.00 per common share (the "Offering"). TransAlta Renewables granted to the underwriters an option (the "Over-Allotment Option"), exercisable in whole or in part for a period of 30 days following Closing, to purchase, at the Offering price, up to an additional 3.0 million common shares (representing 15 per cent of the common shares offered under the prospectus).

On Aug. 29, 2013, TransAlta Renewables completed the Offering and issued 20.0 million common shares for gross proceeds of $200 million. The net proceeds of the Offering were used by TransAlta Renewables to repay the $187 million Closing Note issued to the Corporation. On Aug. 29, 2013, the underwriters exercised their Over-Allotment Option in part to purchase an additional 2.1 million common shares at the Offering price of $10.00 per common share for gross proceeds of $21 million. TransAlta Renewables used the net proceeds received from the partial exercise of the Over-Allotment Option to repay a portion of the amount outstanding under the Acquisition Note issued to TransAlta. The remaining principal amount of $9 million outstanding under the Acquisition Note after such payment has been converted into 0.9 million common shares of TransAlta Renewables on the basis of one common share for each $10.00 owing to the Corporation under the Acquisition Note. After completion of the transactions, the Corporation owns 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.

Effective Aug. 9, 2013, the net earnings and total comprehensive income (loss) attributable to the 19.3 per cent divested interest are reflected in net earnings (loss) attributable to non-controlling interests and total comprehensive income (loss) attributable to non-controlling interests, respectively, on the Consolidated Statements of Earnings (Loss) and on the Consolidated Statements of Comprehensive Income (Loss), respectively. The excess of consideration received over the net book value of the Corporation's divested interest was $4 million and was recorded in retained earnings (deficit). As at Dec. 31, 2013, the net assets attributable to the 19.3 per cent divested interest are reflected in equity attributable to non-controlling interests in the Consolidated Statements of Financial Position.

## 5. California Claim

In response to complaints filed by San Diego Gas & Electric Company, the California Attorney General, and other government agencies, the Federal Energy Regulatory Commission ("FERC") ordered TransAlta to refund approximately U.S.$47 million for sales made by it in the organized markets of the California Power Exchange, the California Independent System Operator, and the California Department of Water Resources during the 2000 – 2001 period. In addition, the California parties have sought additional refunds, which to date have been rejected by FERC. TransAlta established a U.S.$47 million provision to cover any potential refunds. Final rulings are not expected in the near future.

For the year ended Dec. 31, 2013, the Corporation accrued for a potential settlement of all outstanding disputes with the California parties, which resulted in a pre-tax charge to earnings of approximately U.S.$52 million.

## 6. 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, the pre-tax income statement impact of the ruling that has been recorded under the caption "Sundance Units 1 and 2 return to service" in the Consolidated Statements of Earnings (Loss) was $254 million.

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. The Corporation has issued notices to the buyers regarding the cessation of the force majeure period for the two units.

## 7. SunHills Mining Limited Partnership

Effective Jan. 17, 2013, the Corporation assumed, through its wholly owned 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 during the first quarter, along with the corresponding liabilities.

The Corporation also entered into finance leases for mining equipment that was in use, or committed to, by PMRL for mining operations. As a result, $33 million in mining equipment has been capitalized to PP&E and the related finance lease obligations recognized during 2013. At the end of the lease terms, the Corporation is eligible to purchase the assets for a nominal amount. The amounts payable under the finance leases are further discussed in Note 12(B).

# 8. Acquisitions and Disposals

## A. Acquisitions

### I. 2013

On Dec. 20, 2013, the Corporation completed the acquisition of a 144 megawatt ("MW") wind farm in Wyoming ("Wyoming Wind") from an affiliate of NextEra Energy Resources, LLC. The total cash consideration transferred was U.S.$102 million ($109 million). The acquisition is TransAlta's first wind project in the Western United States and aligns with the Corporation's strategy of growing its renewables platform and diversifying its presence in that region.

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

| | |
|---|---|
| **Assets:** | |
| Property, plant, and equipment | 79 |
| Intangible assets | 20 |
| Goodwill | 13 |
| Total assets acquired | 112 |
| **Liabilities:** | |
| Decommissioning and restoration provision | 3 |
| Total liabilities assumed | 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.

The initial accounting for the acquisition has been provisionally determined, as certain joint tax elections are still to be agreed upon and completed by the Corporation and the seller, and the elected amounts could impact the acquisition date fair values.

Revenue of $1 million and net earnings of $1 million attributable to the operations of the Wyoming Wind farm have been included in net earnings, from Dec. 20, 2013.

### 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 power station was commissioned in the fourth quarter of 2013. 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 12(A)).

### III. 2011

On Nov. 1, 2011, the Corporation purchased the remaining 50 per cent of the Taylor Hydro jointly controlled asset from Capital Power, the joint venture partner, for $7 million. As the Corporation acquired control of the overall business, the entire asset was remeasured at the acquisition-date fair value.

## B. Disposals

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.

During 2011, the Corporation sold its biomass facility located in Grande Prairie. The sale was effective Sept. 1, 2011 and closed on Oct. 1, 2011. As a result, the Corporation realized a pre-tax gain of $9 million. During 2012, the Corporation realized a pre-tax gain of $3 million resulting from the release of the remaining consideration related to the achievement of the Environmental Attribute Conditions by the purchaser.

## 9. Gain on Sale of (Reserve on) 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 posted by the Corporation. As a result, a pre-tax gain of $15 million ($11 million after tax) was realized. The claim, filed during the first quarter of 2012, related primarily to the Corporation's collateral on foreign futures transactions.

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,* the Securities Investor Protection Corp. was overseeing a liquidation of the broker-dealer to return assets to customers. A trustee had been appointed to take control of and liquidate the assets of MF Global Inc. and return client collateral. A significant portion of TransAlta's collateral related to collateral on foreign futures transactions that would have been in accounts in the United Kingdom ("U.K.") and was subject to a dispute between the U.S. trustee and the U.K. administrator. In December 2011, TransAlta had net collateral of approximately U.S.$36 million with MF Global Inc. and due to the uncertainty of collection, a U.S.$18 million reserve was recognized. At Dec. 31, 2011, the net amount of the collateral had been reclassified to a long-term asset on the Consolidated Statements of Financial Position.

## 10. Insurance Recovery

During 2013, the Corporation realized a pre-tax gain of $8 million relating to business interruption insurance claims made as a result of the flooding during the second quarter of 2013 and forced outages at the Corporation's gas and hydro facilities in 2011.

## 11. Expenses by Nature

Expenses classified by nature are as follows:

| **Year ended Dec. 31** | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| | **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 | **778** | **–** | 645 | – | 714 | – |
| Purchased power | **85** | **–** | 63 | – | 138 | – |
| Depreciation | **58** | **–** | 41 | – | 40 | – |
| Salaries and benefits | **5** | **251** | 4 | 261 | 3 | 296 |
| Other operating expenses | **–** | **265** | – | 238 | – | 256 |
| **Total** | **926** | **516** | 753 | 499 | 895 | 552 |

# 12. Leases

## A. The Corporation as Lessor

### I. Finance Leases

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

| As at Dec. 31 | 2013 | | 2012 | |
|---|---|---|---|---|
| | **Minimum lease payments** | **Present value of minimum lease payments** | Minimum lease payments | Present value of minimum lease payments |
| Within one year | **50** | **46** | 46 | 43 |
| Second to fifth years inclusive | **209** | **143** | 194 | 132 |
| More than five years | **494** | **160** | 513 | 158 |
| | **753** | **349** | 753 | 333 |
| Less: unearned finance lease income | **548** | **-** | 558 | - |
| Add: unguaranteed residual value | **175** | **31** | 164 | 26 |
| **Total finance leases receivable** | **380** | **380** | 359 | 359 |
| Included in the Consolidated Statements of Financial Position as: | | | | |
| Current portion of finance lease receivable | **3** | | 2 | |
| Finance lease receivable | **377** | | 357 | |
| | **380** | | 359 | |

The interest rates inherent in the leases are fixed at the contract date for the entire lease term and are approximately 17 per cent and 12 per cent per annum, respectively, for the Fort Saskatchewan and the Solomon finance leases.

### II. Operating Leases

Several of the Corporation's PPAs and other long-term contracts meet the criteria of operating leases. Total rental income, including contingent rent, related to these contracts and reported in revenues in the Consolidated Statements of Earnings (Loss) for the year ended Dec. 31, 2013 was $208 million (2012 – $188 million, 2011 – $159 million).

## B. The Corporation as Lessee

### I. Finance Leases

Amounts payable under the Corporation's finance leases for mining equipment (see Note 7) are as follows:

| As at | Dec. 31, 2013 | |
|---|---|---|
| | Minimum lease payments | Present value of minimum lease payments |
| Within one year | 9 | 9 |
| Second to fifth years inclusive | 18 | 16 |
| | 27 | 25 |
| Less: interest cost | 2 | – |
| **Total finance lease obligation** | 25 | 25 |
| Included in the Consolidated Statements of Financial Position as: | | |
| Current portion of finance lease obligation | 8 | |
| Finance lease obligation | 17 | |
| | 25 | |

### II. Operating Leases

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

During the year ended Dec. 31, 2013, $10 million (2012 – $13 million, 2011 – $12 million) was recognized as an expense in the Consolidated Statements of Earnings (Loss) in respect of these operating leases. No sublease payments were received or made, nor were any contingent rental payments made in respect of these operating leases.

Future minimum lease payments required under non-cancellable operating leases are as follows:

| | |
|---|---|
| 2014 | 12 |
| 2015 | 10 |
| 2016 | 10 |
| 2017 | 8 |
| 2018 | 7 |
| 2019 and thereafter | 52 |
| **Total minimum lease payments** | **99** |

# 13. Asset Impairment Charges and Reversals

## A. Renewables

During 2013, the Corporation recognized a total pre-tax impairment charge of $4 million related to three contracted hydro assets within the renewables fleet. 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 are based on estimates of fair value less costs to sell derived from long range forecasts. The impairment losses are included in the Generation Segment.

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

## B. 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. While no impairment losses were recognized in 2013 for the Alberta Merchant CGU, total pre-tax impairment losses of $23 million that were recognized previously on renewables plants that now form part of the Alberta Merchant CGU were reversed. The Alberta Merchant CGU's recoverable amount was based on an estimate of fair value less costs to sell using a discounted cash flow methodology, based on the Corporation's long range forecasts and prices evidenced in the marketplace.

The pre-tax reversal is recognized in the Generation Segment.

## C. 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 recoverable amount was based on an estimate of fair value less costs to sell, 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. The impairment assessment was based on an estimate of fair value less costs to sell, derived from the cash flows expected to result under the provisions of the PPA. The loss and reversal were included in the Generation Segment.

## D. Centralia Thermal

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 Centralia Thermal 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 Thermal plant to Puget Sound Energy ("PSE") 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 included in the Generation Segment during 2012. The impairment assessment was based on whether the carrying amount of the Centralia Thermal plant was recoverable based on an estimate of fair value less costs to sell.

## E. Reversals

Impairment charges can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants improve.

## 14. Investments

The Corporation's investments in joint ventures accounted for using the equity method consist of its investments in CE Gen, Wailuku, TAMA Transmission LP, and CalEnergy, LLC ("CalEnergy").

The change in investments is as follows:

| | |
|---|---|
| Balance, Dec. 31, 2011 | 193 |
| Equity loss | (15) |
| Distributions received | (1) |
| Change in foreign exchange rates | (5) |
| Balance, Dec. 31, 2012 | 172 |
| Equity loss | (10) |
| Addition to equity investments | 17 |
| Change in foreign exchange rates | 13 |
| **Balance, Dec. 31, 2013** | **192** |

Summarized financial information on the results of operations and financial position relating to the Corporation's pro-rata interests in CE Gen, Wailuku, TAMA Transmission LP, and CalEnergy is as follows:

| **Year ended Dec. 31** | **2013** | 2012 | 2011 |
|---|---|---|---|
| **Results of operations** | | | |
| Revenues | **108** | 101 | 133 |
| Expenses | **(118)** | (116) | (119) |
| **Proportionate share of net earnings (loss)** | **(10)** | (15) | 14 |

Summarized financial information relating to 100 per cent of CE Gen, including adjustments for the application of consistent accounting policies and the Corporation's purchase price adjustments, is as follows:

| **Year ended Dec. 31** | **2013** | 2012 | 2011 |
|---|---|---|---|
| Revenues | **212** | 197 | 263 |
| Depreciation and amortization | **85** | 86 | 96 |
| Interest expense | **21** | 22 | 29 |
| Income tax recovery | **(23)** | (26) | (7) |
| Net loss | **(19)** | (30) | (25) |
| Other comprehensive loss | **(1)** | – | – |
| Total comprehensive loss | **(20)** | (30) | (25) |
| Distributions received | **–** | – | 15 |

| **As at Dec. 31** | **2013** | 2012 |
|---|---|---|
| Current assets | **107** | 93 |
| Long-term assets | **658** | 675 |
| Current liabilities | **(76)** | (62) |
| Long-term liabilities | **(361)** | (409) |
| Net assets | **328** | 297 |
| **Additional items included above** | | |
| Cash and cash equivalents | **50** | 27 |
| Current financial liabilities[1] | **(48)** | (35) |
| Long-term financial liabilities[1] | **(201)** | (233) |

1 *Excludes trade and other payables and provisions*

A reconciliation of the carrying amount to the Corporation's 50 per cent interest in the CE Gen joint venture is as follows:

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Net assets | **328** | 297 |
| Less: minority interest in CE Gen | **(13)** | (14) |
| Less: 50 per cent of CE Gen's net assets not owned by the Corporation | **(128)** | (116) |
| Net investment | **187** | 167 |

CE Gen's ability to make distributions to its owners, including the Corporation, is restricted by covenants and conditions, including principal and interest funding deposit requirements imposed by certain project-related debt agreements.

At Dec. 31, 2013, the carrying amount of the Corporation's net investment in Wailuku, TAMA Transmission LP, and CalEnergy is $5 million (2012 – $5 million).

On Feb. 20, 2014, the Corporation announced an agreement to sell the Corporation's 50 per cent ownership of CE Gen and Wailuku (see Note 43).

## 15. Net Interest Expense

The components of net interest expense are as follows:

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Interest on debt | **240** | 227 | 228 |
| Interest income | **–** | (2) | – |
| Capitalized interest *(Note 24)* | **(2)** | (4) | (31) |
| Ineffectiveness on hedges | **–** | 4 | (1) |
| **Interest expense** | **238** | 225 | 196 |
| Accretion of provisions *(Note 28)* | **18** | 17 | 19 |
| **Net interest expense** | **256** | 242 | 215 |

The Corporation capitalizes interest during the construction phase of growth capital projects. The capitalized interest in 2013 and 2012 related to the New Richmond wind farm. The capitalized interest in 2011 relates primarily to Keephills Unit 3.

# 16. Income Taxes

## A. Consolidated Statements of Earnings (Loss)

### I. Rate Reconciliations

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Earnings (loss) before income taxes** | **(12)** | (445) | 449 |
| Equity (income) loss *(Note 14)* | **10** | 15 | (14) |
| Net earnings attributable to non-controlling interests | **(29)** | (37) | (38) |
| **Adjusted earnings (loss) before income taxes** | **(31)** | (467) | 397 |
| Statutory Canadian federal and provincial income tax rate (%) | **25.0** | 25.0 | 26.5 |
| Expected income tax expense (recovery) | **(8)** | (117) | 105 |
| Increase (decrease) in income taxes resulting from: | | | |
| Lower effective foreign tax rates | **(21)** | (49) | (3) |
| Resolution of uncertain tax matters | **(1)** | (27) | – |
| Statutory and other rate differences | **(5)** | 7 | (1) |
| Writedown of deferred income tax assets | **28** | 289 | – |
| Other | **(1)** | (1) | 5 |
| **Income tax expense (recovery)** | **(8)** | 102 | 106 |
| **Effective tax rate** *(%)* | **26** | (22) | 27 |

### II. Components of Income Tax Expense

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

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Current income tax expense | **38** | 27 | 26 |
| Adjustments in respect of current income tax of previous years | **1** | (3) | – |
| Adjustments in respect of deferred income tax of previous years | **(1)** | 1 | – |
| Deferred income tax expense (recovery) related to the origination and reversal of temporary differences | **(68)** | (71) | 78 |
| Deferred income tax expense (recovery) resulting from changes in tax rates or laws[1] | **(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) expense arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense | **(1)** | (16) | 2 |
| Deferred income tax expense arising from the writedown of deferred income tax assets | **28** | 168 | – |
| **Income tax expense (recovery)** | **(8)** | 102 | 106 |

1 *On June 20, 2012, the Ontario budget bill froze the Ontario general corporate tax rate at 11.5 per cent. The Corporation had been using the previously substantively enacted tax rate of 10.0 per cent. During 2013, the Corporation adjusted the deferred tax rate to incorporate the Ontario M&P tax credit, which reduced the corporate tax rate back to 10.0 per cent. During 2013, changes in provincial rates were enacted in British Columbia and New Brunswick.*

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Current income tax expense | **39** | 13 | 26 |
| Deferred income tax expense (recovery) | **(47)** | 89 | 80 |
| **Income tax expense (recovery)** | **(8)** | 102 | 106 |

## 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 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Income tax expense (recovery) related to: | | | |
| Net impact related to cash flow hedges | 12 | (15) | (101) |
| Net impact related to net investment hedges | (5) | 2 | (5) |
| Net actuarial losses | 11 | (8) | (7) |
| Common and preferred share issuance costs | – | (5) | (2) |
| **Income tax expense (recovery) reported in equity** | **18** | (26) | (115) |

## C. Consolidated Statements of Financial Position

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

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Net operating loss carryforwards | 665 | 574 |
| Future decommissioning and restoration costs | 91 | 91 |
| Property, plant, and equipment | (923) | (865) |
| Risk management assets and liabilities, net | (24) | (21) |
| Employee future benefits and compensation plans | 60 | 67 |
| Interest deductible in future periods | 63 | 57 |
| Allowance for doubtful accounts | 18 | 18 |
| Foreign exchange differences on U.S.-denominated debt | 6 | (24) |
| Deferred coal rights revenue | 13 | – |
| Other deductible temporary differences | 7 | 9 |
| Net deferred income tax liability, before writedown of deferred income tax assets | (24) | (94) |
| Writedown of deferred income tax assets[1] | (317) | (289) |
| Net deferred income tax liability, after writedown of deferred income tax assets | (341) | (383) |

1 *During 2013, the Corporation wrote off $28 million (2012 – $289 million) of deferred income tax assets related to approximately $80 million (2012 – $826 million) of deductible temporary differences of its U.S. operations. The deferred income tax assets relate mainly to property, plant, and equipment, future decommissioning and restoration costs, undeducted interest, and net operating losses that expire between 2021 and 2033.*

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

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Deferred income tax assets[1] | 118 | 90 |
| Deferred income tax liabilities | (459) | (473) |
| **Net deferred income tax liability** | **(341)** | (383) |

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

## D. Contingencies

As of Dec. 31, 2013, the Corporation had recognized a net liability of $8 million (2012 – $9 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

| | |
|---|---|
| Balance, Dec. 31, 2011 | (43) |
| Decrease as a result of settlements with taxation authorities | 34 |
| 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)** |

# 17. Accounts Receivable

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Gross accounts receivable | **522** | 643 |
| Allowance for doubtful accounts *(Note 5)* | **(49)** | (46) |
| **Net accounts receivable** | **473** | 597 |

The change in allowance for doubtful accounts is as follows:

| | |
|---|---|
| Balance, Dec. 31, 2011 | 47 |
| Change in foreign exchange rates | (1) |
| Balance, Dec. 31, 2012 | 46 |
| Change in foreign exchange rates | 3 |
| **Balance, Dec. 31, 2013** | **49** |

# 18. Non-Controlling Interests

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

| Subsidiary/Operation | Non-controlling interest |
|---|---|
| TransAlta Cogeneration L.P. | 49.99% – Canadian Power Holdings Inc. |
| TransAlta Renewables | 19.30% – Public shareholders |
| Kent Hills wind farm[1] | 17% – Natural Forces Technologies Inc. |

1 *Owned by TransAlta Renewables.*

## A. Summarized Financial Information Relating to Subsidiaries with Significant Non-Controlling Interests

### I. TransAlta Cogeneration L.P.

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Results of operations** | | | |
| Revenues | **295** | 306 | 316 |
| Net earnings | **48** | 69 | 69 |
| Total comprehensive income | **71** | 57 | 31 |
| Amounts attributable to the non-controlling interest: | | | |
| Net earnings | **24** | 34 | 34 |
| Total comprehensive income | **36** | 28 | 16 |
| Distributions paid to Canadian Power Holdings Inc. | **(46)** | (55) | (55) |

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Current assets | **56** | 71 |
| Long-term assets | **632** | 678 |
| Current liabilities | **(56)** | (74) |
| Long-term liabilities | **(68)** | (87) |
| Total equity | **(564)** | (588) |
| Equity attributable to Canadian Power Holdings Inc. | **(280)** | (290) |

### II. TransAlta Renewables

| Year ended Dec. 31 | 2013[1] |
|---|---|
| **Results of operations** | |
| Revenues | **245** |
| Net earnings | **53** |
| Total comprehensive income | **54** |
| Amounts attributable to the non-controlling interests: | |
| Natural Forces Technologies Inc. | |
| Net earnings | **3** |
| Total comprehensive income | **3** |
| Public shareholders | |
| Net earnings | **2** |
| Total comprehensive income | **2** |
| Distributions paid to Natural Forces Technologies Inc. | **(4)** |
| Dividends paid to public shareholders of TransAlta Renewables | **(5)** |

1 *TransAlta Renewables was formed in August 2013; accordingly, a non-controlling interest did not exist prior to 2013 and comparative information is not provided.*

| As at Dec. 31 | 2013 |
|---|---|
| Current assets | **59** |
| Long-term assets | **1,954** |
| Current liabilities | **(100)** |
| Long-term liabilities | **(846)** |
| Total equity | **(1,067)** |
| Equity attributable to Natural Forces Technologies Inc. | **(39)** |
| Equity attributable to public shareholders of TransAlta Renewables | **(198)** |

## B. Consolidated Statements of Earnings (Loss)

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Canadian Power Holdings Inc.'s interest in TransAlta Cogeneration, L.P. | **24** | 34 | 35 |
| Public shareholders' interest in TransAlta Renewables | **2** | – | – |
| Natural Forces Technologies Inc.'s interest in Kent Hills | **3** | 3 | 3 |
| **Total** | **29** | 37 | 38 |

## C. Consolidated Statements of Financial Position

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Canadian Power Holdings Inc.'s interest in TransAlta Cogeneration, L.P. | **280** | 290 |
| Public shareholders' interest in TransAlta Renewables | **198** | – |
| Natural Forces Technologies Inc.'s interest in Kent Hills | **39** | 40 |
| **Total** | **517** | 330 |

The change in non-controlling interests is as follows:

| | |
|---|---|
| Balance, Dec. 31, 2011 | 358 |
| Non-controlling interests' portion of net earnings | 37 |
| Non-controlling interests' portion of OCI | (6) |
| Distributions paid to non-controlling interests | (59) |
| Balance, Dec. 31, 2012 | 330 |
| Formation of TransAlta Renewables | 206 |
| Non-controlling interests' portion of net earnings | 29 |
| Non-controlling interests' portion of OCI | 12 |
| Distributions paid, and payable, to non-controlling interests | (60) |
| **As at Dec. 31, 2013** | **517** |

## D. Consolidated Statements of Cash Flows

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

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| TransAlta Cogeneration, L.P. | **46** | 55 | 57 |
| TransAlta Renewables | **5** | – | – |
| Kent Hills | **4** | 4 | 4 |
| **Total** | **55** | 59 | 61 |

# 19. Financial Instruments

## A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at fair value or amortized cost (see Note 2(C)). The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

**Carrying value of financial instruments as at Dec. 31, 2013**

| | Derivatives used for hedging | Derivatives classified as held for trading | Loans and receivables | Other financial liabilities | Total |
|---|---|---|---|---|---|
| **Financial assets** | | | | | |
| Accounts receivable | – | – | 473 | – | 473 |
| Collateral paid | – | – | 20 | – | 20 |
| Finance lease receivable[1] | – | – | 380 | – | 380 |
| Risk management assets | | | | | |
| Current | 16 | 96 | – | – | 112 |
| Long-term | 250 | 26 | – | – | 276 |
| **Financial liabilities** | | | | | |
| Accounts payable and accrued liabilities | – | – | – | 447 | 447 |
| Finance lease obligation[1] | – | – | 25 | – | 25 |
| Dividends payable | – | – | – | 85 | 85 |
| Risk management liabilities | | | | | |
| Current | 19 | 65 | – | – | 84 |
| Long-term | 232 | 31 | – | – | 263 |
| Long-term debt[1] | – | – | – | 4,322 | 4,322 |

*1 Includes current portion.*

Carrying value of financial instruments as at Dec. 31, 2012

| | Derivatives used for hedging | Derivatives classified as held for trading | Loans and receivables | Other financial liabilities | Total |
|---|---|---|---|---|---|
| Financial assets | | | | | |
| Accounts receivable | – | – | 597 | – | 597 |
| Collateral paid | – | – | 19 | – | 19 |
| Finance lease receivable[2] | – | – | 359 | – | 359 |
| Risk management assets | | | | | |
| Current | 14 | 187 | – | – | 201 |
| Long-term | 18 | 51 | – | – | 69 |
| Financial liabilities | | | | | |
| Accounts payable and accrued liabilities | – | – | – | 495 | 495 |
| Collateral received | – | – | – | 2 | 2 |
| Dividends payable | – | – | – | 75 | 75 |
| Risk management liabilities | | | | | |
| Current | 47 | 120 | – | – | 167 |
| Long-term | 95 | 11 | – | – | 106 |
| Long-term debt[2] | – | – | – | 4,217 | 4,217 |

*2 Includes current portion.*

## B. Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. 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. 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. Energy Trading includes, in Level II, over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

*c. Level III*

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

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 energy trading 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 energy trading fair values are determined at Dec. 31, 2013 is estimated to be a +/- $105 million (2012 – $26 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The 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** | **Fair value as at Dec. 31, 2013** | **Valuation Technique** | **Unobservable input** | **Range** |
|---|---|---|---|---|
| Unit contingent power purchases | 43 | Historical bootstrap | Price discount<br>Volumetric discount[1] | 0–2 per cent<br>0–14 per cent |
| Long-term power sale | 225 | Long-term price forecast | Illiquid future power prices | $34.40–$90.83 |
| Coal supply revenue sharing | (12) | Black-Scholes | Volumes (MWh) | 18–25 per cent of available generation |
| | | | Illiquid future implied volatilities in MidC power | 35 per cent |
| Unit contingent power sales | (5) | Black-Scholes | Illiquid future implied volatilities in MidC power | 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.*

### 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 2013, $28 million of fair value was transferred from Level III net risk management assets to Level II net risk management assets. The trade terms of these contracts were originally beyond a liquid trading period where forward price forecasts were not available for the full period of the contract. During the period, the contract terms were determined to be within a liquid trading period where observable prices were available.

**II. Energy Trading**

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

The following table summarizes the key factors impacting the fair value of the energy trading risk management assets and liabilities by classification level during the years ended Dec. 31, 2013 and 2012, 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, 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) 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 |

| | 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, 2011 | – | (90) | (14) | – | 287 | 7 | – | 197 | (7) |
| Changes attributable to: | | | | | | | | | |
| Market price changes on existing contracts | – | 25 | 10 | – | (3) | 27 | – | 22 | 37 |
| Market price changes on new contracts | – | 7 | – | – | (10) | 4 | – | (3) | 4 |
| Contracts settled | – | 14 | 7 | (1) | (210) | (14) | (1) | (196) | (7) |
| Discontinued hedge accounting on certain contracts | – | (19) | – | – | 15 | 4 | – | (4) | 4 |
| Net risk management assets (liabilities) at Dec. 31, 2012 | – | (63) | 3 | (1) | 79 | 28 | (1) | 16 | 31 |
| Additional Level III information: | | | | | | | | | |
| Gains recognized in OCI | | | 10 | | | – | | | 10 |
| Total gains (losses) included in earnings before income taxes | | | (7) | | | 31 | | | 24 |
| Unrealized gains included in earnings before income taxes relating to net assets held at Dec. 31, 2012 | | | – | | | 17 | | | 17 |

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

The anticipated settlement of the contracts outstanding at Dec. 31, 2013, over each of the next five calendar years and thereafter, is as follows:

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 and thereafter | Total |
|---|---|---|---|---|---|---|---|---|
| Hedges | Level I | – | – | – | – | – | – | – |
| | Level II | (16) | (18) | (21) | (11) | – | – | (66) |
| | Level III | 1 | 1 | 5 | 11 | 12 | 25 | 55 |
| Non-Hedges | Level I | – | – | – | – | – | – | – |
| | Level II | (14) | 13 | 12 | 3 | – | – | 14 |
| | Level III | 35 | (6) | (7) | (1) | (1) | (9) | 11 |
| Total | Level I | – | – | – | – | – | – | – |
| | Level II | (30) | (5) | (9) | (8) | – | – | (52) |
| | Level III | 36 | (5) | (2) | 10 | 11 | 16 | 66 |
| **Total net assets (liabilities)** | | **6** | **(10)** | **(11)** | **2** | **11** | **16** | **14** |

### III. Other Risk Management Assets and Liabilities

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

The following tables summarize the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the years ended Dec. 31, 2013 and 2012, 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, 2012 | – | (50) | – | – | 1 | – | – | (49) | – |
| Changes attributable to: | | | | | | | | | |
| Market price changes on existing contracts | – | 41 | – | – | – | – | – | 41 | – |
| Market price changes on new contracts | – | 12 | – | – | – | – | – | 12 | – |
| Contracts settled | – | 23 | – | – | – | – | – | 23 | – |
| **Net risk management assets at Dec. 31, 2013** | **–** | **26** | **–** | **–** | **1** | **–** | **–** | **27** | **–** |

| | Hedges | | | Non-Hedges | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | Level I | Level II | Level III | Level I | Level II | Level III | Level I | Level II | Level III |
| Net risk management liabilities at Dec. 31, 2011 | – | (50) | – | – | – | – | – | (50) | – |
| Changes attributable to: | | | | | | | | | |
| Market price changes on existing contracts | – | (17) | – | – | – | – | – | (17) | – |
| Market price changes on new contracts | – | (7) | – | – | 1 | – | – | (6) | – |
| Contracts settled | – | 24 | – | – | – | – | – | 24 | – |
| Net risk management assets (liabilities) at Dec. 31, 2012 | – | (50) | – | – | 1 | – | – | (49) | – |

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

The anticipated settlement of the contracts outstanding at Dec. 31, 2013, over each of the next five calendar years and thereafter, is as follows:

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 and thereafter | Total |
|---|---|---|---|---|---|---|---|---|
| Hedges | Level I | – | – | – | – | – | – | – |
| | Level II | 12 | 6 | 1 | – | 7 | – | 26 |
| | Level III | – | – | – | – | – | – | – |
| Non-Hedges | Level I | – | – | – | – | – | – | – |
| | Level II | 1 | – | – | – | – | – | 1 |
| | Level III | – | – | – | – | – | – | – |
| Total | Level I | – | – | – | – | – | – | – |
| | Level II | 13 | 6 | 1 | – | 7 | – | 27 |
| | Level III | – | – | – | – | – | – | – |
| **Total net assets** | | **13** | **6** | **1** | **–** | **7** | **–** | **27** |

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

| | Fair value | | | | |
|---|---|---|---|---|---|
| | Level I | Level II | Level III | Total | Total carrying value |
| **Long-term debt[1] – Dec. 31, 2013** | **–** | **4,367** | **–** | **4,367** | **4,262** |
| Long-term debt[1] – Dec. 31, 2012 | – | 4,426 | – | 4,426 | 4,157 |

1 *Includes current portion and excludes U.S.$50 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 book value of other short-term financial assets and liabilities (cash and cash equivalents, 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 19(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 during the year ended Dec. 31, 2013 is as follows:

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

During 2013, the Corporation finalized the Centralia Coal plant contract with PSE. 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 a risk management liability.

# 20. Risk Management Activities

## A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

| As at Dec. 31 | 2013 | | | | | 2012 |
|---|---|---|---|---|---|---|
| | Net investment hedges | Cash flow hedges | Fair value hedges | Not designated as a hedge | Total | Total |
| **Risk management assets** | | | | | | |
| **Energy trading** | | | | | | |
| Current | – | 3 | – | 95 | 98 | 198 |
| Long-term | – | 235 | – | 26 | 261 | 59 |
| Total energy trading risk management assets | – | 238 | – | 121 | 359 | 257 |
| **Other** | | | | | | |
| Current | 1 | 12 | – | 1 | 14 | 3 |
| Long-term | – | 8 | 7 | – | 15 | 10 |
| Total other risk management assets | 1 | 20 | 7 | 1 | 29 | 13 |
| **Risk management liabilities** | | | | | | |
| **Energy trading** | | | | | | |
| Current | – | 18 | – | 65 | 83 | 141 |
| Long-term | – | 231 | – | 31 | 262 | 70 |
| Total energy trading risk management liabilities | – | 249 | – | 96 | 345 | 211 |
| **Other** | | | | | | |
| Current | – | 1 | – | – | 1 | 26 |
| Long-term | – | 1 | – | – | 1 | 36 |
| Total other risk management liabilities | – | 2 | – | – | 2 | 62 |
| **Net energy trading risk management assets (liabilities)** | – | (11) | – | 25 | 14 | 46 |
| **Net other risk management assets (liabilities)** | 1 | 18 | 7 | 1 | 27 | (49) |
| **Net total risk management assets (liabilities)** | 1 | 7 | 7 | 26 | 41 | (3) |

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 | 2013 | | | | 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | 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 | 371 | 270 | (341) | (68) | 522 | 331 | (452) | (317) |
| Gross amounts set-off | (157) | – | 156 | 1 | (252) | (186) | 252 | 186 |
| Net amounts as presented in the Consolidated Statements of Financial Position | 214 | 270 | (185) | (67) | 270 | 145 | (200) | (131) |

## II. Hedges

*a Net Investment Hedges*

i. Hedges of Foreign Operations

The Corporation hedges its net investment in foreign operations with U.S.-denominated borrowings, cross-currency interest rate swaps, and foreign currency forward contracts.

The Corporation's net investment hedges are comprised of U.S. dollar denominated long-term debt with a face value of U.S.$850 million (Dec. 31, 2012 – U.S.$770 million) and the following foreign currency forward contracts:

| As at Dec. 31 | 2013 | | | 2012 | | | |
|---|---|---|---|---|---|---|---|
| **Notional amount sold** | **Notional amount purchased** | **Fair value asset** | **Maturity** | Notional amount sold | Notional amount purchased | Fair value asset | Maturity |
| **Foreign Currency Forward Contracts** | | | | | | | |
| **AUD200** | **CAD188** | **1** | **2014** | AUD175 | CAD181 | 1 | 2013 |
| **USD10** | **CAD11** | **–** | **2014** | USD35 | CAD34 | – | 2013 |

During 2013, the Corporation de-designated $20 million of U.S. dollar denominated debentures from its net investment hedges. The cumulative net foreign exchange gains (losses) related to these hedges up to the date of de-designation will remain in OCI until a disposal of the related U.S. foreign operation occurs. These instruments were designated as part of the Corporation's net investment hedge at Dec. 31, 2012.

During 2012, the Corporation de-designated $300 million of borrowings under a U.S. dollar denominated credit facility, $50 million of U.S. dollar denominated senior notes, and U.S.$60 million of foreign currency forward contracts from its net investment hedges due to a reduction in its investment in U.S. foreign operations arising from the Centralia Thermal plant impairment. The cumulative net foreign exchange gains (losses) related to these hedges up to the date of de-designation will remain in OCI until a disposal of the related U.S. foreign operation occurs. These instruments were designated as part of the Corporation's net investment hedge at Dec. 31, 2011.

ii. Effect of Net Investment Hedges

The following table summarizes the pre-tax amounts recognized in OCI related to financial instruments used in net investment hedges:

| Year ended | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Financial instruments in net investment hedging relationships** | **Pre-tax gain (loss) recognized in OCI** | Pre-tax gain (loss) recognized in OCI | Pre-tax gain (loss) recognized in OCI |
| Long-term debt | **(53)** | 19 | (23) |
| Foreign currency contracts | **13** | (4) | (15) |
| **OCI impact** | **(40)** | 15 | (38) |

No gains or losses on net investment hedges were reclassified from OCI in 2013, 2012, or 2011.

For the year ended Dec. 31, 2013, a net after-tax gain of $2 million (2012 – loss of $10 million, 2011 – loss of $1 million), relating to the translation of the Corporation's net investment in foreign operations, net of hedging, was recognized in OCI. All net investment hedges currently have no ineffective portion.

*b. Cash Flow Hedges*

i. Energy Trading Risk Management

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

| As at Dec. 31 | 2013 | | 2012 | |
|---|---|---|---|---|
| **Type** *(thousands)* | **Notional amount sold** | **Notional amount purchased** | Notional amount sold | Notional amount purchased |
| **Electricity** *(MWh)* | **5,977** | **–** | 5,624 | – |
| **Natural gas** *(GJ)* | **963** | **35,775** | 570 | 37,827 |
| **Oil** *(gallons)* | **–** | **4,116** | – | 4,116 |

During 2013, unrealized pre-tax gains of $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, 2013.

During 2013, unrealized pre-tax gains of nil (2012 – $90 million gain, 2011 – $207 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 during 2012 and 2013. 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 current forward prices that will change between now and the time the contracts will be 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 will not change.

During 2012, the Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Dec. 31, 2013, cumulative gains of $4 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions 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 | 2013 | | | 2012 | | | |
|---|---|---|---|---|---|---|---|
| **Notional amount sold** | **Notional amount purchased** | **Fair value asset** | **Maturity** | Notional amount sold | Notional amount purchased | Fair value asset (liability) | Maturity |
| **Foreign Exchange Forward Contracts – foreign-denominated receipts/expenditures** | | | | | | | |
| **USD4** | **CAD4** | **–** | **2014** | USD3 | CAD3 | – | 2013 |
| **CAD3** | **EUR2** | **–** | **2014** | CAD32 | EUR25 | 1 | 2013 |
| **CAD220** | **USD205** | **2** | **2014-2018** | CAD245 | USD228 | (12) | 2013-2017 |
| **Foreign Exchange Forward Contracts – foreign-denominated debt** | | | | | | | |
| **CAD52** | **USD50** | **2** | **2014** | CAD50 | USD50 | – | 2013 |
| **–** | **–** | **–** | **–** | CAD314 | USD300 | (14) | 2013 |
| **CAD106** | **USD100** | **1** | **2014** | CAD100 | USD100 | – | 2013 |
| **CAD310** | **USD300** | **9** | **2014** | CAD308 | USD300 | (8) | 2013 |
| **USD100** | **CAD107** | **–** | **2014** | – | – | – | – |
| **CAD22** | **USD20** | **–** | **2014** | – | – | – | – |
| **Cross-Currency Swaps – foreign-denominated debt** | | | | | | | |
| **CAD530** | **USD500** | **4** | **2015** | CAD530 | USD500 | (28) | 2015 |

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, 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** |
| Commodity contracts | **11** | Revenue | **36** | Revenue | **(2)** |
| 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 hedges | **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 |
| Commodity contracts | 36 | Revenue | 15 | Revenue | (90) |
| 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 hedges | (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) |

Year ended Dec. 31, 2011

| | Effective portion | | | Ineffective portion | |
|---|---|---|---|---|---|
| Derivatives in cash flow hedging relationships | Pre-tax gain (loss) recognized in OCI | Location of (gain) loss reclassified from OCI | Pre-tax (gain) loss reclassified from OCI | Location of (gain) loss reclassified from OCI | Pre-tax (gain) loss recognized in earnings |
| Commodity contracts | (92) | Revenue | (43) | Revenue | (207) |
| Foreign exchange forwards on commodity contracts | 3 | Revenue | - | Revenue | - |
| Foreign exchange forwards on project hedges | (6) | Property, plant, and equipment | - | Foreign exchange (gain) loss | - |
| Foreign exchange forwards on U.S. debt hedges | 3 | Foreign exchange (gain) loss | (36) | Foreign exchange (gain) loss | - |
| Cross-currency swaps | 7 | Foreign exchange (gain) loss | 13 | Foreign exchange (gain) loss | - |
| Forward starting interest rate swaps | (25) | Interest expense | 2 | Interest expense | - |
| OCI impact | (110) | OCI impact | (64) | Net earnings impact | (207) |

Over the next 12 months, the Corporation estimates that $20 million of after-tax losses 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 will 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 (Dec. 31, 2011 – 5.75 and 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** | **2013** | | 2012 | | |
|---|---|---|---|---|---|
| **Notional amount** | **Fair value asset** | **Maturity** | Notional amount | Fair value asset | Maturity |
| **USD50** | **7** | **2018** | USD50 | 10 | 2018 |

Including the interest rate swaps above, 21 per cent of the Corporation's debt as at Dec. 31, 2013 is subject to floating interest rates (2012 – 24 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** | | **2013** | 2012 | 2011 |
|---|---|---|---|---|
| **Derivatives in fair value hedging relationships** | **Location of gain (loss) recognized in earnings** | | | |
| Interest rate contracts | Net interest expense | **(2)** | (16) | 4 |
| Long-term debt | Net interest expense | **2** | 15 | (3) |
| **Earnings (loss) impact** | | **–** | (1) | 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. *Energy Trading Risk Management*

| **As at Dec. 31** | **2013** | | 2012 | |
|---|---|---|---|---|
| **Type** *(Thousands)* | **Notional amount sold** | **Notional amount purchased** | Notional amount sold | Notional amount purchased |
| **Electricity** *(MWh)* | **34,741** | **24,456** | 40,962 | 32,051 |
| **Natural gas** *(GJ)* | **215,730** | **224,661** | 1,021,137 | 1,018,557 |
| **Emissions** *(tonnes)* | **70** | **70** | 138 | 128 |
| **Oil** *(gallons)* | **–** | **9,576** | – | 7,560 |

*b. Other Non-Hedge Derivatives*

| **As at Dec. 31** | **2013** | | | 2012 | | | |
|---|---|---|---|---|---|---|---|
| **Notional amount sold** | **Notional amount purchased** | **Fair value asset** | **Maturity** | Notional amount sold | Notional amount purchased | Fair value asset | Maturity |
| **Foreign Exchange Forward Contracts** | | | | | | | |
| **–** | **–** | **–** | **–** | CAD21 | AUD20 | – | 2013 |
| **CAD91** | **USD85** | **1** | **2014** | CAD127 | USD128 | 1 | 2013-2014 |

*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, 2013, the Corporation recognized a net unrealized loss of $40 million (2012 – loss of $123 million, 2011 – gain of $123 million) related to commodity derivatives.

For the year ended Dec. 31, 2013, a gain of $8 million (2012 – loss of $4 million, 2011 – loss of $4 million) related to foreign exchange and other derivatives was recognized and is comprised of a net unrealized loss of $1 million (2012 – gain of $1 million, 2011 – gain of $3 million) and a net realized gain of $9 million (2012 – loss of $5 million, 2011 – loss of $7 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 Trading Segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

In compliance with the Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board of Directors approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance – covariance approach.

VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

The Corporation recognizes the limitations of VaR and actively uses other controls, including restrictions on authorized instruments, volumetric and term limits, stress-testing of individual portfolios and of the total proprietary trading portfolio, and management reviews when loss limits are triggered.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2013 associated with the Corporation's proprietary energy trading activities was $2 million (2012 – $2 million, 2011 – $5 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, 2013 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $42 million (2012 – $5 million, 2011 – $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, 2013 associated with these transactions was $11 million (2012 – $9 million, 2011 – $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, for the years ended Dec. 31, 2013, 2012, and 2011, 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 25 basis point (2012 – 50 basis point, 2011 – 50 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

| Year ended Dec. 31 | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| | **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 | – | 4 | (8) |

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

c *Currency Rate Risk*

The Corporation has exposure to various currencies, such as the euro, the U.S. dollar, and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI, for the years ended Dec. 31, 2013, 2012, and 2011, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average five cent (2012 – five cent, 2011 – six cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

| **Year ended Dec. 31** | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| **Currency** | **Net earnings increase**[1] | **OCI gain**[1,2] | Net earnings decrease[1] | OCI gain[1,2] | Net earnings decrease[1] | OCI gain[1,2] |
| USD | **2** | **8** | (2) | 11 | (4) | 11 |
| EUR | **–** | **–** | – | 1 | – | 3 |
| **Total** | **2** | **8** | (2) | 12 | (4) | 14 |

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 Thermal 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, 2013:

| *(Per cent)* | **Investment grade** | **Non-investment grade** | **Total** |
|---|---|---|---|
| Accounts receivable | **90** | **10** | **100** |
| Risk management assets | **99** | **1** | **100** |

The Corporation's maximum exposure to credit risk at Dec. 31, 2013, 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, 2013 was $23 million (2012 – $25 million).

At Dec. 31, 2013, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at year-end. The Corporation has evaluated the risk of default related to this counterparty to be minimal.

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the year is presented in Note 17.

### III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. Investment grade ratings support these activities and provide better access to capital markets through commodity and credit cycles. TransAlta is focused on maintaining a strong financial position and stable investment grade credit ratings.

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

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Exposure Management Committee, senior management, and the Board of Directors; and maintaining investment grade credit ratings.

A maturity analysis of the Corporation's net financial liabilities, as at Dec. 31, 2013, is as follows:

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 and thereafter | Total |
|---|---|---|---|---|---|---|---|
| Accounts payable and accrued liabilities | 447 | – | – | – | – | – | 447 |
| Debt[1] | 209 | 689 | 29 | 854 | 732 | 1,807 | 4,320 |
| Energy trading risk management (assets) liabilities | (6) | 10 | 11 | (2) | (11) | (16) | (14) |
| Other risk management (assets) liabilities | (13) | (6) | (1) | – | (7) | – | (27) |
| Interest on long-term debt[2] | 211 | 178 | 172 | 162 | 123 | 783 | 1,629 |
| Dividends payable | 85 | – | – | – | – | – | 85 |
| **Total** | **933** | **871** | **211** | **1,014** | **837** | **2,574** | **6,440** |

1 *Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2015 and 2017.*
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, 2013, the Corporation provided $20 million (2012 – $19 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, 2013, the Corporation received nil (2012 – $2 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

### III. 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, 2013, the Corporation had posted collateral of $94 million (2012 – $85 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 $88 million of collateral to its counterparties based upon the value of the derivatives at Dec. 31, 2013.

## 21. Restricted Cash

At Dec. 31, 2012, $2 million of cash and cash equivalents was restricted due to Project Pioneer and was not available for general use.

## 22. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which 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** | **2013** | 2012 *(Restated)** |
|---|---|---|
| Coal | **53** | 78 |
| Deferred stripping costs | **13** | 9 |
| Natural gas | **5** | 2 |
| Purchased emission credits | **6** | 4 |
| **Total** | **77** | 93 |

** See Note 2 for prior period restatements.*

The change in inventory is as follows:

| | |
|---|---|
| Balance, Dec. 31, 2011 | 92 |
| Net additions | 46 |
| Writedowns | (52) |
| Reversal of writedowns | 8 |
| Change in foreign exchange rates | (1) |
| Balance, Dec. 31, 2012 | 93 |
| Net additions | 7 |
| Writedowns | (22) |
| Change in foreign exchange rates | (1) |
| **Balance, Dec. 31, 2013** | **77** |

No inventory is pledged as security for liabilities.

## 23. Income Taxes Receivable

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million. The appeal decision from the Federal Court was received on Jan. 20, 2012, and the ruling was in TransAlta's favour. The Crown had 60 days from the date of judgment to appeal the decision. No appeal was filed by the Crown. TransAlta received $9 million in 2012 and the remaining $2 million in 2013.

## 24. Property, Plant, and Equipment

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

| | Land | Thermal generation | Gas generation | Renewable generation | Mining property and equipment | Assets under construction | Capital spares and other[1] | Total |
|---|---|---|---|---|---|---|---|---|
| **Cost** | | | | | | | | |
| As at Dec. 31, 2011 | 74 | 5,539 | 1,843 | 2,506 | 945 | 196 | 283 | 11,386 |
| Additions | – | – | – | 1 | – | 683 | 19 | 703 |
| Disposals | – | (10) | (1) | – | – | – | – | (11) |
| Asset impairment charges *(Note 13)* | – | (378) | – | (18) | (12) | – | – | (408) |
| Asset impairment reversals *(Note 13)* | – | 29 | – | – | 12 | – | – | 41 |
| Revisions and additions to decommissioning and restoration costs | – | (14) | 11 | (4) | (6) | – | – | (13) |
| Retirement of assets | – | (145) | (22) | (8) | (9) | – | (1) | (185) |
| Change in foreign exchange rates | – | (20) | (1) | – | (1) | (1) | (1) | (24) |
| Transfers | 1 | 383 | 40 | 59 | 30 | (536) | 15 | (8) |
| As at Dec. 31, 2012 | 75 | 5,384 | 1,870 | 2,536 | 959 | 342 | 315 | 11,481 |
| Additions | – | – | – | – | – | 534 | 27 | 561 |
| Additions – finance lease *(Note 7)* | – | – | – | – | 33 | – | – | 33 |
| Acquisition of Wyoming wind farm *(Note 8)* | – | – | – | 78 | – | – | 1 | 79 |
| Disposals | (1) | – | – | – | (3) | – | – | (4) |
| Asset impairment (charges) reversals *(Note 13)* | – | – | (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** |
| **Accumulated depreciation** | | | | | | | | |
| As at Dec. 31, 2011 | – | 2,386 | 802 | 449 | 411 | – | 67 | 4,115 |
| Depreciation | – | 257 | 97 | 87 | 38 | – | 12 | 491 |
| Retirement of assets | – | (120) | (17) | (3) | (6) | – | – | (146) |
| Change in foreign exchange rates | – | (13) | (1) | – | (1) | – | – | (15) |
| Transfers | – | – | (7) | (1) | – | – | – | (8) |
| 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 |
| Asset impairment (charges) reversals *(Note 13)* | – | – | – | 2 | – | – | – | 2 |
| Transfers | – | – | (5) | – | – | – | – | (5) |
| **As at Dec. 31, 2013** | **–** | **2,692** | **946** | **615** | **488** | **–** | **90** | **4,831** |
| **Carrying amount** | | | | | | | | |
| As at Dec. 31, 2011 | 74 | 3,153 | 1,041 | 2,057 | 534 | 196 | 216 | 7,271 |
| 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** |

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 $2 million of interest to PP&E in 2013 (2012 – $4 million) at a weighted average rate of 5.46 per cent (2012 – 5.41 per cent).

## 25. 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** | **2013** | 2012 |
|---|---|---|
| Energy Trading | **30** | 30 |
| Renewables | **–** | 417 |
| Renewables and Alberta Merchant | **417** | – |
| U.S. Operations | **13** | – |
| **Total goodwill** | **460** | 447 |

In assessing whether goodwill is impaired, the carrying amount of the CGUs (including goodwill) is compared with the recoverable amount of the CGU. The recoverable amount is the higher of fair value less costs to sell and value in use. The impairment review for goodwill is conducted annually. The recoverable amounts exceeded the carrying amounts of the CGUs and there was no impairment of goodwill in 2013, 2012, or 2011.

In 2012, $417 million of the Corporation's goodwill was allocated to the Renewables CGU, which was comprised of all of the Corporation's merchant and contracted wind and hydro facilities, and assessed for impairment.

In 2013, as part of the annual impairment review and assessment process for the Corporation's PP&E assets, the Alberta plants that have significant merchant capacity were considered to be one CGU (the "Alberta Merchant CGU") (see Note 13). The Corporation's merchant renewables facilities were assigned to this CGU. Consequently, the $417 million of goodwill that was tested for impairment in 2012 at the Renewables CGU level has been tested at the combined Renewables and Alberta Merchant CGUs group level.

The Corporation determined the recoverable amount of the Renewables and Alberta Merchant CGUs group by calculating its fair value less cost to sell using discounted cash flow projections. The Corporation's long-range forecasts, which represent forecasted cash flows for generating facilities over their expected useful lives, ranging from 5 to 59 years, are the primary source of information for determining fair value. They contain forecasts for production and sale of electricity, revenues, operating costs, and capital expenditures. In developing these plans, various assumptions, such as electricity prices, natural gas prices, and cost inflation rates are established. These assumptions take into account existing and forecast prices, regional supply-demand balances, other macroeconomic factors, and historical trends and variability. The results of the long-range forecasts are reviewed and approved by senior management.

The key assumptions impacting the determination of fair value for the Renewables and Alberta Merchant CGUs group are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historic production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each 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. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. Discount rates used for the Renewables and Alberta Merchant CGUs group goodwill impairment calculation ranged from 4.9 per cent to 7.1 per cent.

No reasonably possible change in the assumptions would result in any impairment of goodwill.

The goodwill resulting from the Wyoming Wind farm acquisition has been assigned to the U.S. Operations CGU.

## 26. 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, 2011 | 152 | 127 | 173 | 18 | 470 |
| Additions | 6 | – | – | 33 | 39 |
| Retirements | – | (5) | – | – | (5) |
| Transfers | – | 11 | – | (11) | – |
| As at Dec. 31, 2012 | 158 | 133 | 173 | 40 | 504 |
| Additions | 20 | – | – | 29 | 49 |
| Acquisition of Wyoming wind farm *(Note 8)* | – | – | 20 | – | 20 |
| Retirements | – | (10) | – | – | (10) |
| Transfers | – | 50 | – | (47) | 3 |
| **As at Dec. 31, 2013** | **178** | **173** | **193** | **22** | **566** |
| **Accumulated amortization** | | | | | |
| As at Dec. 31, 2011 | 96 | 79 | 19 | – | 194 |
| Amortization | 4 | 19 | 8 | – | 31 |
| Retirements | – | (5) | – | – | (5) |
| 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** |
| Carrying amount | | | | | |
| As at Dec. 31, 2011 | 56 | 48 | 154 | 18 | 276 |
| As at Dec. 31, 2012 | 58 | 40 | 146 | 40 | 284 |
| **As at Dec. 31, 2013** | **74** | **69** | **158** | **22** | **323** |

## 27. Other Assets

The components of other assets are as follows:

| **As at Dec. 31** | **2013** | 2012 |
|---|---|---|
| Deferred licence fees | **18** | 21 |
| Project development costs | **36** | 35 |
| Deferred service costs | **19** | 19 |
| Long-term prepaids | **17** | 5 |
| Keephills Unit 3 transmission deposit | **6** | 7 |
| Other | **1** | 3 |
| **Total other assets** | **97** | 90 |

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.

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

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee 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 nine years, as long as certain performance criteria are met.

# 28. Decommissioning and Other Provisions

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

| | Decommissioning and restoration | Restructuring | Other | Total |
|---|---|---|---|---|
| Balance, Dec. 31, 2011 | 301 | – | 81 | 382 |
| Liabilities incurred | 16 | 13 | 56 | 85 |
| Liabilities settled | (44) | (5) | (17) | (66) |
| Accretion | 16 | – | 1 | 17 |
| Revisions in estimated cash flows | (11) | – | 2 | (9) |
| Revisions in discount rates | (15) | – | – | (15) |
| Reversals[1] | – | – | (81) | (81) |
| Change in foreign exchange rates | (1) | – | – | (1) |
| 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 *(Note 8)* | 3 | – | – | 3 |
| Change in foreign exchange rates | 4 | – | 1 | 5 |
| **Balance, Dec. 31, 2013** | **270** | **–** | **62** | **332** |

*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, 2012 | 262 | 8 | 42 | 312 |
| Current portion | 13 | 8 | 12 | 33 |
| Non-current portion | 249 | – | 30 | 279 |
| **Balance, Dec. 31, 2013** | **270** | **–** | **62** | **332** |
| Current portion | **11** | **–** | **5** | **16** |
| Non-current portion | **259** | **–** | **57** | **316** |

## 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 2013 and 2072. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2013, the Corporation had provided a surety bond in the amount of U.S.$136 million (2012 – U.S.$136 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2013, the Corporation had provided letters of credit in the amount of $115 million (2012 – $79 million) in support of future decommissioning obligations at the Alberta mine.

## 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.

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.

# 29. Long-Term Debt

## A. Debt and Credit facilities

The amounts outstanding are as follows:

| **As at Dec. 31** | **2013** | | | 2012 | | |
|---|---|---|---|---|---|---|
| | **Carrying value** | **Face value** | **Interest**[1] | Carrying value | Face value | Interest[1] |
| Credit facilities[2] | **852** | **852** | **2.6%** | 950 | 950 | 2.4% |
| Debentures | **1,269** | **1,251** | **6.1%** | 839 | 851 | 6.6% |
| Senior notes[3] | **1,797** | **1,809** | **5.6%** | 2,017 | 1,990 | 5.6% |
| Non-recourse[4] | **376** | **380** | **5.9%** | 375 | 380 | 5.9% |
| Other | **28** | **28** | **6.3%** | 36 | 36 | 6.5% |
| | **4,322** | **4,320** | | 4,217 | 4,207 | |
| Less: recourse current portion | **(209)** | **(209)** | | (606) | (606) | |
| Less: non-recourse current portion | **–** | **–** | | (1) | (1) | |
| **Total long-term debt** | **4,113** | **4,111** | | 3,610 | 3,600 | |

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. Includes U.S.$300 million at Dec. 31, 2013 (Dec. 31, 2012 – U.S.$300 million).*
3 *U.S. face value at Dec. 31, 2013 – U.S.$1.7 billion (Dec. 31, 2012 – U.S.$2.0 billion).*
4 *Includes U.S.$20 million at Dec. 31, 2013 (Dec. 31, 2012 – U.S.$20 million).*

A portion of the Corporation's fixed rate debentures and senior notes have been hedged using fixed to floating interest rate swaps (see Note 20) and are recorded at fair value. The balance of long-term debt is not hedged and is recorded at amortized cost.

**Credit facilities** are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's U.S.$300 million committed 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. In May 2013, the Corporation completed a renewal of its four-year revolving $1.5 billion committed syndicated credit facility and extended its maturity to 2017. In June 2013, the U.S.$300 million bilateral credit facility was renewed for 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 was renewed in November 2013, for a two-year term to 2015.

Of the $2.1 billion (2012 – $2.0 billion) of committed credit facilities, $0.9 billion (2012 – $0.8 billion) is not drawn, and is available as of Dec. 31, 2013, subject to customary borrowing conditions. In addition to the $0.9 billion available under the credit facilities, TransAlta also has $42 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 2014 to 2030. 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 4.50 per cent to 6.65 per cent and have maturity dates ranging from 2015 to 2040. A total of U.S.$850 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 issued by CHD 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, and includes U.S.$20 million of U.S.-denominated debt.

**Other** consists of notes payable for the Windsor plant that bear interest at a fixed rate of 7.4 per cent, mature in November 2014, and are recourse to the Corporation through a standby letter of credit; and an unsecured commercial loan obligation that bears interest at a rate of 5.9 per cent, matures in 2023, and requires annual blended payments of interest and principal.

TransAlta's debt contains terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2013, the Corporation was in compliance with all debt covenants.

## B. Restrictions

Debt of $7 million related to the Windsor plant, owned by the Corporation's TA Cogen subsidiary, include principal and interest funding provisions that restrict the Corporation's ability to access funds generated by the operations of the plant. The Corporation has provided a letter of credit in the amount of the funding requirements, thereby permitting it to access the funds.

Debentures of $341 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

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 and thereafter | Total |
|---|---|---|---|---|---|---|---|
| Principal repayments[1] | 209 | 689 | 29 | 854 | 732 | 1,807 | **4,320** |

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

## D. 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, 2013 was $370 million (2012 – $336 million) with no (2012 – nil) amounts exercised by third parties under these arrangements.

# 30. Deferred Credits and Other Long-Term Liabilities

The components of deferred credits and other long-term liabilities are as follows:

| As at Dec. 31 | 2013 | 2012 |
|---|---|---|
| Deferred coal revenues | **52** | 51 |
| Defined benefit obligations | **200** | 220 |
| Long-term incentive accruals | **16** | 15 |
| Other | **72** | 15 |
| **Total deferred credits and other long-term liabilities** | **340** | 301 |

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint venture 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 a $13 million reimbursement received for costs of the New Richmond terminal station, which will be amortized into revenue over the term of the related PPA, and $28 million relating to the California claim (see Note 5).

# 31. Common Shares

## A. Issued and Outstanding

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

| As at Dec. 31 | 2013 | | 2012 | |
|---|---|---|---|---|
| | **Common shares** *(millions)* | **Amount** | Common shares *(millions)* | Amount |
| Issued and outstanding, beginning of period | **254.7** | **2,730** | 223.6 | 2,274 |
| Issued under the dividend reinvestment and share purchase plan | **13.5** | **186** | 9.7 | 159 |
| Issued under share-based payment plans | **-** | **-** | 0.1 | 1 |
| Issued under the PSOP *(Note 34)* | **-** | **-** | 0.1 | 1 |
| Issued under public offering[1] | **-** | **-** | 21.2 | 295 |
| | **268.2** | **2,916** | 254.7 | 2,730 |
| Amounts receivable under Employee Share Purchase Plan | **-** | **(3)** | - | (4) |
| **Issued and outstanding, end of year** | **268.2** | **2,913** | 254.7 | 2,726 |

1 *Net of after-tax issuance costs of $9 million ($12 million issuance costs, less tax-effects of $3 million)*

On Sept. 13, 2012, TransAlta completed a public offering of 19,250,000 common shares at a price of $14.30 per common share. TransAlta granted the underwriters an over-allotment option to purchase up to an additional 2,887,500 common shares at the same price. On Sept. 20, 2012, the underwriters exercised in part their over-allotment option and purchased an additional 1,992,000 common shares at $14.30 per common share for total gross proceeds of $304 million.

## B. Shareholder Rights Plan

The primary objective of the Shareholder Rights Plan is to provide the Corporation's Board of Directors sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. The 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

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan was called the Premium Dividend™, Dividend Reinvestment, and Optional Common Share Purchase Plan ("the Plan") and it 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, 2014, 2.1 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 | 2013 | 2012 | 2011 |
|---|---|---|---|
| Net earnings (loss) attributable to common shareholders | **(71)** | (615) | 290 |
| Basic and diluted weighted average number of common shares outstanding | **264** | 235 | 222 |
| Net earnings (loss) per share attributable to common shareholders, basic and diluted | **(0.27)** | (2.62) | 1.31 |

The effect of the stock options, PSOP, and the Plan does not materially affect the calculation of the total weighted average number of common shares outstanding (see Note 34).

## E. Dividends

The following table summarizes the common share dividends declared in 2013, 2012, and 2011:

| Date declared | Payment date | Dividend per share ($) | Total dividends | Dividends paid in cash | Dividends paid in shares |
|---|---|---|---|---|---|
| **2013** | | | | | |
| **Oct. 30, 2013** | **Jan. 1, 2014** | **0.29** | **78** | **50** | **28** |
| **July 23, 2013** | **Oct. 1, 2013** | **0.29** | **77** | **51** | **26** |
| **Apr. 22, 2013** | **July 1, 2013**[1] | **0.29** | **76** | **21** | **55** |
| **Jan. 28, 2013** | **Apr. 1, 2013** | **0.29** | **75** | **22** | **53** |
| 2012 | | | | | |
| Oct. 24, 2012 | Jan. 1, 2013 | 0.29 | 73 | 20 | 53 |
| July 13, 2012 | Oct. 1, 2012 | 0.29 | 67 | 18 | 49 |
| Apr. 25, 2012 | July 1, 2012 | 0.29 | 66 | 18 | 48 |
| Jan. 25, 2012 | Apr. 1, 2012 | 0.29 | 65 | 23 | 43 |
| 2011 | | | | | |
| Oct. 27, 2011 | Jan. 1, 2012 | 0.29 | 65 | 45 | 20 |
| July 27, 2011 | Oct. 1, 2011 | 0.29 | 65 | 48 | 17 |
| Apr. 28, 2011 | July 1, 2011 | 0.29 | 64 | 48 | 16 |

1 *Dividends of $20 million were paid on June 28, 2013.*

# 32. Preferred Shares

## A. Issued and Outstanding

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

| As at Dec. 31 | 2013 | | 2012 | | | |
|---|---|---|---|---|---|---|
| Cumulative Redeemable Rate Reset First Preferred Shares | Number of shares *(millions)* | Amount | Number of shares *(millions)* | Amount | Dividend rate per share *($)* | Redemption price per share *($)* |
| Series A | **12** | **293** | 12 | 293 | 1.15 | 25.00 |
| Series C | **11** | **269** | 11 | 269 | 1.15 | 25.00 |
| Series E | **9** | **219** | 9 | 219 | 1.25 | 25.00 |
| Issued and outstanding, end of period | **32** | **781** | 32 | 781 | | |

On Aug. 10, 2012, TransAlta completed a public offering of 9 million Series E Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $225 million. The holders of the preferred shares are entitled to receive fixed cumulative cash dividends at an annual rate of $1.25 per share as approved by the Board of Directors, payable quarterly, yielding 5.0 per cent per annum, for the initial period ending Sept. 30, 2017. The dividend rate will reset on Sept. 30, 2017 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 3.65 per cent. The preferred shares are redeemable at the option of TransAlta on or after Sept. 30, 2017 and on Sept. 30 of every fifth year thereafter at a price of $25.00 per share plus all declared and unpaid dividends.

The Series E preferred shareholders will have the right at their option to convert their shares into Series F Cumulative Redeemable Rate Reset First Preferred Shares on Sept. 30, 2017 and on Sept. 30 of every fifth year thereafter. The holders of Series F preferred shares will be entitled to receive quarterly floating rate cumulative dividends as approved by the Board of Directors at a yield per annum equal to the sum of the then three-month Government of Canada Treasury Bill rate plus 3.65 per cent.

## B. Dividends

The following table summarizes the preferred share dividends declared in 2013, 2012, and 2011:

| | | Series A | | Series C | | Series E | |
|---|---|---|---|---|---|---|---|
| **Date declared** | **Payment date** | **Dividend per share** *($)* | **Total dividends** | **Dividend per share** *($)* | **Total dividends** | **Dividend per share** *($)* | **Total dividends** |
| **2013** | | | | | | | |
| **Oct. 30, 2013** | **Dec. 31, 2013** | **0.2875** | **4** | **0.2875** | **3** | **0.3125** | **3** |
| **July 23, 2013** | **Sept. 30, 2013** | **0.2875** | **3** | **0.2875** | **4** | **0.3125** | **2** |
| **Apr. 22, 2013** | **June 30, 2013** | **0.2875** | **4** | **0.2875** | **3** | **0.3125** | **3** |
| **Jan. 28, 2013** | **March 31, 2013** | **0.2875** | **3** | **0.2875** | **3** | **0.3125** | **3** |
| 2012 | | | | | | | |
| Oct. 24, 2012 | Dec. 31, 2012 | 0.2875 | 3 | 0.2875 | 4 | 0.4897 | 4 |
| July 13, 2012 | Sept. 30, 2012 | 0.2875 | 4 | 0.2875 | 3 | – | – |
| Apr. 25, 2012 | June 30, 2012 | 0.2875 | 4 | 0.2875 | 3 | – | – |
| Jan. 25, 2012 | March 31, 2012 | 0.2875 | 3 | 0.3844[1] | 4 | – | – |
| 2011 | | | | | | | |
| Oct. 27, 2011 | Dec. 31, 2011 | 0.2875 | 4 | – | – | – | – |
| July 27, 2011 | Sept. 30, 2011 | 0.2875 | 4 | – | – | – | – |
| Apr. 28, 2011 | June 30, 2011 | 0.2875 | 3 | – | – | – | – |

1 *Includes dividends of $0.0969 per share ($1 million in total) for the period from Nov. 29, 2011 to Dec. 31, 2011, which were accrued at Dec. 31, 2011.*

# 33. Accumulated Other Comprehensive Income (Loss)

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

| | **2013** | 2012 *(Restated)** |
|---|---|---|
| **Currency translation adjustment** | | |
| Opening balance, Jan. 1 | **(38)** | (28) |
| Gains (losses) on translating net assets of foreign operations | **37** | (23) |
| Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[1] | **(35)** | 13 |
| **Balance, Dec. 31** | **(36)** | (38) |
| **Cash flow hedges** | | |
| Opening balance, Jan. 1 | **(37)** | (28) |
| Gains (losses) on derivatives designated as cash flow hedges, net of tax[2] | **41** | (9) |
| **Balance, Dec. 31** | **4** | (37) |
| **Employee future benefits** | | |
| Opening balance, Jan. 1 | **(61)** | (38) |
| Net actuarial gains (losses) on defined benefit plans, net of tax[3] | **31** | (23) |
| **Balance, Dec. 31** | **(30)** | (61) |
| **Accumulated other comprehensive loss** | **(62)** | (136) |

** See Note 3 for prior period restatements.*
*1 Net of income tax recovery of 5 for the year ended Dec. 31, 2013 (2012 – 2 expense).*
*2 Net of income tax expense of 12 for the year ended Dec. 31, 2013 (2012 – 15 expense).*
*3 Net of income tax expense of 11 for the year ended Dec. 31, 2013 (2012 – 8 recovery).*

# 34. Share-Based Payment Plans

At Dec. 31, 2013, the Corporation had two types of share-based payment plans and an employee share purchase plan.

The Corporation is authorized to grant employees options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares as determined on the grant date. The Corporation has reserved 13.0 million common shares for issue.

## A. Stock Option Plans

### I. Canadian Employee Plan

This plan is offered to all full-time and part-time employees in Canada below the level of manager. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

### II. U.S. Plan

This plan mirrors the rules of the Canadian plan and is offered to all full-time and part-time employees in the U.S.

### III. Australian Phantom Plan

This plan is offered to all full-time and part-time employees in Australia below the level of manager. Options under this plan are not physically granted; rather, employees receive the equivalent value of shares in cash when exercised. Options granted under this plan may not be exercised until one year after grant and thereafter at an amount not exceeding 25 per cent of the grant per year on a cumulative basis until the fifth year, after which the entire grant may be exercised until the tenth year, which is the expiry date.

## IV. Total Plan Information

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2013 are outlined below:

| | Options outstanding | | | Options exercisable | |
|---|---|---|---|---|---|
| **Range of exercise prices** *($ per share)* | **Number outstanding at Dec. 31, 2013** *(millions)* | **Weighted average remaining contractual life** *(years)* | **Weighted average exercise price** *($ per share)* | **Number exercisable at Dec. 31, 2013** *(millions)* | **Weighted average exercise price** *($ per share)* |
| 15.41–22.46 | 0.8 | 4.8 | 19.84 | 0.7 | 20.70 |
| 31.97-35.05 | 0.6 | 4.1 | 32.41 | 0.6 | 32.41 |
| **10.85–35.05** | **1.4** | **4.5** | **25.71** | **1.3** | **26.11** |

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

| **Year ended Dec. 31** | **2013** | | 2012 | | 2011 | |
|---|---|---|---|---|---|---|
| | **Number of share options** *(millions)* | **Weighted average exercise price** *($ per share)* | Number of share options *(millions)* | Weighted average exercise price *($ per share)* | Number of share options *(millions)* | Weighted average exercise price *($ per share)* |
| Outstanding, beginning of year | **1.5** | **25.35** | 1.7 | 24.94 | 2.2 | 24.94 |
| Forfeited | **(0.1)** | **25.45** | (0.2) | 22.81 | (0.5) | 25.35 |
| **Outstanding, end of year** | **1.4** | **25.71** | 1.5 | 25.35 | 1.7 | 24.94 |

The Corporation uses the fair value method of accounting for awards granted under its stock option plans. No stock options were granted in 2013, 2012, or 2011.

The expense recognized arising from equity-settled share-based payment transactions was nil (2012 – $1 million, 2011 – $2 million).

## B. Performance Share Ownership Plan

Under the terms of the PSOP, which commenced in 1997, the Corporation is authorized to award to employees and directors up to an aggregate of 4.0 million common shares. During 2010, the authorized amount was increased to 6.5 million common shares. The number of common shares that could be issued under both the PSOP and the share option plans, however, cannot exceed 13.0 million common shares. Participants in the PSOP receive grants that, after three years, make them eligible to receive a set number of common shares, including the value of reinvested dividends over the period, or cash equivalent up to the maximum of the grant amount plus any accrued dividends thereon. The ultimate awarding of PSOP in any year is at the discretion of TransAlta's Human Resource Committee ("HRC"). Once a participant's PSOP eligibility for an award has been established, 50 per cent of the shares may be released to the participant when the Board of Directors use share settlements on the awards, while the remaining 50 per cent will be held in trust for one additional year for employees below vice-president level, and for two additional years for employees at the vice-president level and above. If the awards are paid out in cash, they are paid immediately. The actual number of common shares or cash equivalent a participant may receive is determined by the percentile ranking of the total shareholder return over three years of the Corporation's common shares amongst the companies comprising the comparator group. The expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is valued using the closing share price.

The granting of PSOP units was discontinued following the 2012 – 2014 grants. The plan will continue until the end of this last cycle.

| **Year ended Dec. 31** *(millions)* | **2013** | 2012 | 2011 |
|---|---|---|---|
| Number of grants outstanding, beginning of year | **2.9** | 2.5 | 1.7 |
| Granted | **–** | 1.5 | 1.4 |
| Awarded by HRC | **–** | (0.1) | – |
| Forfeited | **(1.0)** | (1.0) | (0.6) |
| **Number of grants outstanding, end of year** | **1.9** | 2.9 | 2.5 |

In 2013, pre-tax PSOP compensation recovery was $6 million (2012 – $3 million expense, 2011 – $9 million expense), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss). In 2013, no common shares (2012 – 55,418 common shares, 2011 – 50,560 common shares) were issued (2012 – $15.12 per share, 2011 – $21.15 per share).

### C. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation will extend an interest-free loan (up to 30 per cent of an employee's base salary) to employees below executive level and allow for payroll deductions over a three-year period to repay the loan. Executives are not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent will purchase these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares are handled in the same manner. At Dec. 31, 2013, amounts receivable from employees under the plan totalled $3 million (2012 – $4 million).

## 35. 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. The pension plans are administered by TransAlta, the Plan sponsor, through its Pension Committee. 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 newly acquired SunHills plans, 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, 2013 and Jan. 1, 2013, respectively. The measurement date used to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2013.

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 2013 with an effective date of Dec. 31, 2012. The last actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2013.

The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $63 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuation of the Canadian and U.S. plans was as at Dec. 31, 2013 and Jan. 1, 2013, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2013.

Effective Jan. 17, 2013, TransAlta assumed, through SunHills, operations and management control of the Highvale Mine from PMRL. SunHills assumed responsibility for both defined benefit and defined contribution pension plans and the required pension funding obligations (see Note 7).

## B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution, and other health and dental benefit plans are as follows:

| **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 |

| Year ended Dec. 31, 2011 | Registered | Supplemental | Other | Total |
|---|---|---|---|---|
| Current service cost | 2 | 2 | 2 | 6 |
| Administration expenses | 1 | – | – | 1 |
| Interest cost on defined benefit obligation | 19 | 4 | 1 | 24 |
| Interest on plan assets | (15) | – | – | (15) |
| Past service costs | – | 1 | – | 1 |
| Defined benefit expense | 7 | 7 | 3 | 17 |
| Defined contribution expense | 19 | – | – | 19 |
| Net expense | 26 | 7 | 3 | 36 |

## C. Status of Plans

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

| **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)** |

| As at Dec. 31, 2012 | Registered | Supplemental | Other | Total |
|---|---|---|---|---|
| Fair value of plan assets | 294 | 5 | – | 299 |
| Present value of defined benefit obligation | (424) | (77) | (34) | (535) |
| Funded status – plan deficit | (130) | (72) | (34) | (236) |
| Amount recognized in the consolidated financial statements: | | | | |
| Accrued current liabilities | (9) | (5) | (2) | (16) |
| Other long-term liabilities | (121) | (67) | (32) | (220) |
| Total amount recognized | (130) | (72) | (34) | (236) |

## D. Plan Assets

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

| | Registered | Supplemental | Other | Total |
|---|---|---|---|---|
| Fair value of plan assets as at Dec. 31, 2011 | 294 | 5 | – | 299 |
| Interest on plan assets | 13 | – | – | 13 |
| Net return on plan assets | 11 | – | – | 11 |
| Contributions | 3 | 6 | 2 | 11 |
| Benefits paid | (26) | (6) | (2) | (34) |
| Administration expenses | (2) | – | – | (2) |
| Effect of translation on U.S. plans | 1 | – | – | 1 |
| Fair value of plan assets as at Dec. 31, 2012 | **294** | **5** | **–** | **299** |
| Acquisition of SunHills 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** |

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

| **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 | **–** | **58** | **–** | **58** |
| A | **–** | **46** | **–** | **46** |
| BBB | **–** | **13** | **–** | **13** |
| Below BBB | **–** | **2** | **–** | **2** |
| Money market and cash and cash equivalents | **14** | **–** | **–** | **14** |
| **Total** | **14** | **381** | **6** | **401** |

| Year ended Dec. 31, 2012 | Level I | Level II | Level III | Total |
|---|---|---|---|---|
| Equity securities | | | | |
| Canadian | – | 66 | – | 66 |
| U.S. | – | 41 | – | 41 |
| International | – | 36 | – | 36 |
| Private | – | – | 6 | 6 |
| Bonds | | | | |
| AAA | – | 41 | – | 41 |
| AA | – | 48 | – | 48 |
| A | 1 | 37 | – | 38 |
| BBB | – | 11 | – | 11 |
| Below BBB | – | 2 | – | 2 |
| Money market and cash and cash equivalents | 10 | – | – | 10 |
| **Total** | 11 | 282 | 6 | 299 |

Plan assets do not include any common shares of the Corporation at Dec. 31, 2013 and Dec. 31, 2012. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2013 (2012 – $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, 2011 | 396 | 71 | 32 | 499 |
| Current service cost | 2 | 2 | 1 | 5 |
| Interest cost | 18 | 3 | 2 | 23 |
| Benefits paid | (26) | (6) | (2) | (34) |
| Actuarial loss arising from financial assumptions | 32 | 8 | 2 | 42 |
| Actuarial (gain) loss arising from experience assumptions | 3 | (1) | (1) | 1 |
| Effect of translation on U.S. plans | (1) | – | – | (1) |
| Present value of defined benefit obligation as at Dec. 31, 2012 | 424 | 77 | 34 | 535 |
| Acquisition of SunHills 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 assumptions | **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** |

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2013 is 13.2 years.

## F. Contributions

The expected employer contributions for 2014 for the defined benefit pension and other post-employment benefit plans are as follows:

| | Registered | Supplemental | Other | Total |
|---|---|---|---|---|
| Expected employer contributions | 12 | 5 | 2 | 19 |

## 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, 2013 | | | As at Dec. 31, 2012 | | |
|---|---|---|---|---|---|---|
| *(per cent)* | **Registered** | **Supplemental** | **Other** | Registered | Supplemental | Other |
| **Accrued benefit obligation** | | | | | | |
| Discount rate | **4.6** | **4.5** | **4.5** | 4.0 | 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 | **-** | **-** | **7.7**[1] | - | - | 7.4[3] |
| Dental care cost escalation | **-** | **-** | **4.0** | - | - | 4.0 |
| Provincial health care premium escalation | **-** | **-** | **5.0** | - | - | 3.5 |
| **Benefit cost for the year** | | | | | | |
| Discount rate | **4.1** | **4.0** | **3.9** | 4.8 | 4.8 | 4.8 |
| Rate of compensation increase | **3.0** | **3.0** | **-** | 3.0 | 3.0 | - |
| Assumed health care cost trend rate | | | | | | |
| Health care cost escalation | **-** | **-** | **7.4**[2] | - | - | 8.0[3] |
| Dental care cost escalation | **-** | **-** | **4.0** | - | - | 4.0 |
| Provincial health care premium escalation | **-** | **-** | **3.5** | - | - | 6.0 |

1 *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.*

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 0.5 per cent per year to 5 per cent in 2018 for Canada.*

3 *Decreasing gradually to 5 per cent by 2018 for both the U.S. and Canadian plans.*

## 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, 2013** | **Registered** | **Supplemental** | **Other** | **Pension** | **Other** |
| 1% increase in the discount rate | **64** | **11** | **2** | **3** | **1** |
| 1% increase in the salary scale | **7** | **8** | **-** | **-** | **-** |
| 1% increase in the health care cost trend rate | **-** | **-** | **2** | **-** | **1** |
| 10% improvement in mortality rates | **15** | **2** | **-** | **1** | **-** |

## 36. Joint Arrangements

Joint arrangements at Dec. 31, 2013 included the following:

| Joint operations | Ownership *(per cent)* | Description |
|---|---|---|
| Sheerness | 50 | Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power |
| Fort Saskatchewan | 60 | Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta |
| McBride Lake | 50 | Wind generation facilities in Alberta operated by TransAlta |
| Goldfields Power | 50 | Gas-fired plant in Australia operated by TransAlta |
| Genesee Unit 3 | 50 | Coal-fired plant in Alberta operated by Capital Power Corporation |
| Keephills Unit 3 | 50 | Coal-fired plant in Alberta operated by TransAlta |
| Soderglen | 50 | Wind generation facilities in Alberta operated by TransAlta |
| Pingston | 50 | Hydro facility in British Columbia operated by TransAlta |
| TransAlta MidAmerican Partnership | 50 | Strategic partnership to develop, build, and operate new natural gas-fuelled electricity generation projects in Canada |

| Joint ventures | Ownership *(per cent)* | Description |
|---|---|---|
| CE Gen | 50 | Geothermal and gas plants in the United States operated by CE Gen affiliates |
| Wailuku | 50 | A run-of-river generation facility in Hawaii operated by MidAmerican Energy Holdings Company |
| CalEnergy | 50 | Strategic partnership to market geothermal capacity |
| TAMA Transmission LP | 50 | Strategic partnership to develop and operate transmission projects in Alberta |

## 37. Changes in Non-Cash Operating Working Capital

| Year ended Dec. 31 | 2013 | 2012 | 2011 |
|---|---|---|---|
| (Use) source: | | | |
| Accounts receivable | **125** | (22) | (131) |
| Prepaid expenses | **(7)** | 3 | 3 |
| Income taxes receivable | **(14)** | (10) | 13 |
| Inventory | **15** | (3) | (26) |
| Accounts payable, accrued liabilities, and provisions | **(51)** | (8) | 15 |
| Income taxes payable | **6** | (16) | 7 |
| **Change in non-cash operating working capital** | **74** | (56) | (119) |

## 38. Capital

TransAlta's capital is comprised of the following:

| As at Dec. 31 | 2013 | 2012 | Increase/ (decrease) |
|---|---|---|---|
| Current portion of long-term debt | **209** | 607 | (398) |
| Less: available cash and cash equivalents[1] | **(42)** | (25) | (17) |
| | **167** | 582 | (415) |
| Long-term debt | **4,113** | 3,610 | 503 |
| Equity | | | |
| Common shares | **2,913** | 2,726 | 187 |
| Preferred shares | **781** | 781 | – |
| Contributed surplus | **9** | 9 | – |
| Deficit | **(735)** | (362) | (373) |
| Accumulated other comprehensive loss | **(62)** | (136) | 74 |
| Non-controlling interests | **517** | 330 | 187 |
| | **7,536** | 6,958 | 578 |
| **Total capital** | **7,703** | 7,540 | 163 |

1 *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.*

Changes in the balances of the components of capital are as follows:

**Long-term debt (including current portion)** increased primarily due to unfavourable changes in foreign exchange rates (see Note 29).

**Common shares** increased in 2013 as a result of the issuance of 13.5 million shares for $186 million under the dividend reinvestment and share purchase plan (see Note 31).

**AOCI** increased in 2013 primarily due to the recognition of gains on derivatives designated as hedging instruments and net actuarial gains on defined benefit plans (see Note 33).

**Non-controlling interests** increased primarily due to the formation of TransAlta Renewables (see Note 4).

TransAlta's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2012 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. TransAlta monitors key credit ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and seeks to manage the Corporation's capital in line with the following targets:

| As at Dec. 31 | 2013 | 2012 | Target |
|---|---|---|---|
| Adjusted cash flow to interest coverage *(times)*[1,2] | **4.0** | 4.4 | 4 to 5 |
| Adjusted cash flow to debt *(%)*[1,2] | **16.9** | 19.0 | 20 to 25 |
| Debt to comparable earnings before interest, taxes, depreciation, and amortization *(times)* | **4.2** | 4.1 | 4 to 5 |

1 *Last 12 months.*
2 *Adjusted for the impacts associated with the California claim in 2013 and the Sundance Units 1 and 2 arbitration in 2012.*

**Adjusted cash flow to interest coverage** is calculated as cash flow from operating activities before changes in working capital plus net interest expense divided by interest on debt less interest income. Adjusted cash flow to interest coverage decreased in 2013 compared to 2012 primarily due to higher interest on debt. The Corporation's goal is to maintain this ratio in a range of four to five times.

**Adjusted cash flow to debt** is calculated as cash flow from operating activities before changes in working capital divided by average total debt less average cash and cash equivalents. Adjusted cash flow to debt decreased in 2013 compared to 2012 due to higher average debt levels in 2013. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

**Debt to comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA")** is calculated as net debt (current and long-term debt 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 business operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

At times, and over a short-term period, the credit ratios may be outside of the specified target ranges while the Corporation realigns the capital structure. During 2013, the Corporation took several steps to strengthen its financial position and reduce debt, using the approximate $221 million in gross proceeds from the initial public offering of TransAlta Renewables (see Note 4) to pay down debt, and utilizing the proceeds from dividends reinvested under the DRASP plan as a continued source of equity. Participation in the dividend reinvestment plan during the fourth quarter of 2013 was approximately 30 to 35 per cent.

TransAlta routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and property, plant, and equipment expenditure requirements.

## B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, and Invest in Property, Plant, and Equipment

For the year ended Dec. 31, 2013 and 2012, net cash outflows, after cash dividends and property, plant, and equipment additions, are summarized below:

| Year ended Dec. 31 | 2013 | 2012 | Increase (decrease) |
|---|---|---|---|
| Cash flow from operating activities | **765** | 520 | 245 |
| Dividends paid on common shares | **(116)** | (104) | (12) |
| Property, plant, and equipment expenditures | **(561)** | (703) | 142 |
| Acquisition of Wyoming Wind farm *(Note 8)* | **(109)** | – | (109) |
| Acquisition of finance lease | **–** | (312) | 312 |
| **Inflow (outflow)** | **(21)** | (599) | 578 |

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2013, $0.9 billion (2012 – $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 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.

During 2013, the Corporation's U.S.$300 million 5.75 per cent senior notes matured and were paid out.

During 2012, the Corporation issued 31.1 million common shares for total gross proceeds of $456 million. The Corporation also issued 9 million Series E Preferred Shares for total gross proceeds of $225 million.

During 2012, the Corporation's U.S.$300 million 6.75 per cent senior notes matured and were paid out. In addition, during 2012, the Corporation issued senior notes in the amount of U.S.$400 million, bearing interest at a rate of 4.5 per cent and maturing in 2022.

Dividends on the Corporation's common shares are at the discretion of the Board of Directors. In determining the payment and level of future dividends, the Board of Directors 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.

# 39. Related Party Transactions

Details of the Corporation's principal operating subsidiaries are as follows:

| Subsidiary | Country | Ownership *(per cent)* | Principal activity |
|---|---|---|---|
| TransAlta Generation Partnership | Canada | 100 | Generation and sale of electricity |
| TransAlta Cogeneration, L.P. | Canada | 50.01 | Generation and sale of electricity |
| TransAlta Centralia Generation, LLC | U.S. | 100 | Generation and sale of electricity |
| TransAlta Energy Marketing Corp. | Canada | 100 | Energy trading |
| TransAlta Energy Marketing (U.S.), Inc. | U.S. | 100 | Energy trading |
| TransAlta Energy (Australia), Pty Ltd. | Australia | 100 | Generation and sale of electricity |
| TransAlta Renewables Inc. | Canada | 80.7 | 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 President – U.S. Operations, all who report directly to the President and CEO, and the Board of Directors. Key management personnel compensation is as follows:

| Year ended Dec. 31 | **2013** | 2012 | 2011 |
|---|---|---|---|
| Total compensation | **15** | 12 | 12 |
| Comprised of: | | | |
| Short-term employee benefits | **7** | 8 | 6 |
| Post-employment benefits | **2** | 1 | 1 |
| Other long-term benefits | **1** | 1 | 1 |
| Termination benefits | **2** | – | – |
| Share-based payment | **3** | 2 | 4 |

## 40. 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 | Total |
|---|---|---|---|---|---|
| 2014 | 39 | 11 | 172 | 42 | 264 |
| 2015 | 14 | 12 | 123 | 26 | 175 |
| 2016 | 13 | 9 | 126 | 25 | 173 |
| 2017 | 13 | 3 | 41 | 20 | 77 |
| 2018 | 12 | 3 | 41 | 27 | 83 |
| 2019 and thereafter | 103 | 6 | 501 | 174 | 784 |
| **Total** | **194** | **44** | **1,004** | **314** | **1,556** |

### 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

Centralia Thermal has various coal supply and associated rail transport contracts to provide coal for use in production. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2025.

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.

### D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for repairs and maintenance that may be required on turbines at various wind facilities as well as an agreement, entered into in 2013, for inspections and parts replacement at two natural gas facilities.

### E. 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 $55 million over the life of the Centralia coal plant to support economic development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination of the MoA this funding will no longer be required.

### F. 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.

# 41. 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.

# 42. Segment Disclosures

## A. Description of Reportable Segments

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

Each segment assumes responsibility for its operating results to operating income (loss). Generation expenses include Energy Trading's intersegment charge for energy marketing. Energy Trading's operating expenses are presented net of these intersegment charges.

The accounting policies of the segments are the same as those described in Note 2. Intersegment transactions are accounted for on a cost-recovery basis that approximates market rates.

## B. Reported Segment Earnings and Segment Assets

### I. Earnings Information

| Year ended Dec. 31, 2013 | Generation | Energy Trading | Corporate | Total |
|---|---|---|---|---|
| Revenues | 2,213 | 79 | – | 2,292 |
| Fuel and purchased power | 926 | – | – | 926 |
| **Gross margin** | 1,287 | 79 | – | 1,366 |
| Operations, maintenance, and administration | 418 | 32 | 66 | 516 |
| Depreciation and amortization | 501 | 1 | 23 | 525 |
| Asset impairment charges (reversals) | (18) | – | – | (18) |
| Inventory writedown | 22 | – | – | 22 |
| Restructuring provision | (2) | – | (1) | (3) |
| Taxes, other than income taxes | 26 | – | 1 | 27 |
| Intersegment cost allocation | 14 | (14) | – | – |
| **Operating income (loss)** | 326 | 60 | (89) | 297 |
| Finance lease income | 46 | – | – | 46 |
| Equity loss | (10) | – | – | (10) |
| California claim | – | (56) | – | (56) |
| Sundance Units 1 and 2 return to service | (25) | – | – | (25) |
| Gain on sale of assets | – | – | 12 | 12 |
| Insurance recovery | 8 | – | – | 8 |
| Foreign exchange gain | | | | 1 |
| Loss on assumption of pension obligations | | | | (29) |
| Net interest expense | | | | (256) |
| **Loss before income taxes** | | | | (12) |

| Year ended Dec. 31, 2012 *(Restated)** | Generation | Energy Trading | Corporate | Total |
|---|---|---|---|---|
| Revenues | 2,207 | 3 | – | 2,210 |
| Fuel and purchased power | 753 | – | – | 753 |
| Gross margin | 1,454 | 3 | – | 1,457 |
| Operations, maintenance, and administration | 388 | 29 | 82 | 499 |
| Depreciation and amortization | 489 | – | 20 | 509 |
| Asset impairment charges | 324 | – | – | 324 |
| Inventory writedown | 44 | – | – | 44 |
| Restructuring provision | 5 | – | 8 | 13 |
| Taxes, other than income taxes | 27 | – | 1 | 28 |
| Intersegment cost allocation | 13 | (13) | – | – |
| Operating income (loss) | 164 | (13) | (111) | 40 |
| Finance lease income | 16 | – | – | 16 |
| Equity loss | (15) | – | – | (15) |
| Sundance Units 1 and 2 return to service | (254) | – | – | (254) |
| Gain on sale of assets | 3 | – | – | 3 |
| Gain on sale of collateral | – | 15 | – | 15 |
| Other income | | | | 1 |
| Foreign exchange loss | | | | (9) |
| Net interest expense | | | | (242) |
| Loss before income taxes | | | | (445) |

** See Note 3 for prior period restatements.*

| Year ended Dec. 31, 2011 *(Restated)** | Generation | Energy Trading | Corporate | Total |
|---|---|---|---|---|
| Revenues | 2,481 | 137 | – | 2,618 |
| Fuel and purchased power | 895 | – | – | 895 |
| Gross margin | 1,586 | 137 | – | 1,723 |
| Operations, maintenance, and administration | 424 | 44 | 84 | 552 |
| Depreciation and amortization | 460 | 1 | 21 | 482 |
| Asset impairment charges | 17 | – | – | 17 |
| Taxes, other than income taxes | 27 | – | – | 27 |
| Intersegment cost allocation | 8 | (8) | – | – |
| Operating income (loss) | 650 | 100 | (105) | 645 |
| Finance lease income | 8 | – | – | 8 |
| Equity gain | 14 | – | – | 14 |
| Gain on sale of assets | 16 | – | – | 16 |
| Reserve on collateral | – | (18) | – | (18) |
| Other income | | | | 2 |
| Foreign exchange loss | | | | (3) |
| Net interest expense | | | | (215) |
| Earnings before income taxes | | | | 449 |

** See Note 3 for prior period restatements.*

Included in the Generation Segment results is $22 million (2012 – $23 million, 2011 – $24 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

## II. Selected Consolidated Statements of Financial Position Information

| **As at Dec. 31, 2013** | **Generation[1]** | **Energy Trading** | **Corporate** | **Total** |
|---|---|---|---|---|
| Goodwill *(Note 25)* | **430** | **30** | **–** | **460** |
| Total segment assets | **9,252** | **244** | **287** | **9,783** |

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

| As at Dec. 31, 2012 | Generation[2] | Energy Trading | Corporate | Total |
|---|---|---|---|---|
| Goodwill *(Note 25)* | 417 | 30 | – | 447 |
| Total segment assets | 8,994 | 262 | 247 | 9,503 |

*2 Total Generation Segment assets include $172 million related to investments in joint arrangements accounted for by the equity method.*

## III. Selected Consolidated Statements of Cash Flows Information

| **Year ended Dec. 31, 2013** | **Generation** | **Energy Trading** | **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 Trading | Corporate | Total |
|---|---|---|---|---|
| Additions to non-current assets: | | | | |
| Property, plant, and equipment | 684 | – | 19 | 703 |
| Intangible assets | 7 | 1 | 31 | 39 |

| Year ended Dec. 31, 2011 | Generation | Energy Trading | Corporate | Total |
|---|---|---|---|---|
| Additions to non-current assets: | | | | |
| Property, plant, and equipment | 445 | – | 8 | 453 |
| Intangible assets | 7 | 1 | 22 | 30 |

## 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** | **2013** | 2012 | 2011 |
|---|---|---|---|
| Depreciation and amortization expense on the Consolidated Statements of Earnings | **525** | 509 | 482 |
| Depreciation included in fuel and purchased power *(Note 11)* | **58** | 41 | 40 |
| Gain on disposal of property, plant, and equipment | **2** | 14 | 10 |
| **Depreciation and amortization on the Consolidated Statements of Cash Flows** | **585** | 564 | 532 |

# C. Geographic Information

## I. Revenues

| **Year ended Dec. 31** | **2013** | 2012 | 2011 |
|---|---|---|---|
| Canada | **1,898** | 1,789 | 1,826 |
| U.S. | **287** | 300 | 674 |
| Australia | **107** | 121 | 118 |
| **Total revenue** | **2,292** | 2,210 | 2,618 |

## II. Non-Current Assets

| | **Property, plant, and equipment** | | **Intangible assets** | | **Other assets** | | **Goodwill** | |
|---|---|---|---|---|---|---|---|---|
| **As at Dec. 31** | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| Canada | **6,538** | 6,437 | **295** | 276 | **57** | 59 | **417** | 417 |
| U.S. | **517** | 443 | **24** | 4 | **21** | 8 | **43** | 30 |
| Australia | **138** | 164 | **4** | 4 | **19** | 23 | **–** | – |
| **Total** | **7,193** | 7,044 | **323** | 284 | **97** | 90 | **460** | 447 |

## 43. Subsequent Events

### A. Sale of CE Gen, Blackrock Development Project, and Wailuku

On Feb. 20, 2014, TransAlta announced an agreement to sell the Corporation's 50 per cent ownership of CE Gen, the Blackrock development project ("Blackrock"), and Wailuku to MidAmerican Renewables for proceeds of U.S.$193.5 million. MidAmerican Renewables holds the other 50 per cent interest in CE Gen, Blackrock, and Wailuku.

### B. Dividend

On Feb. 20, 2014, the Corporation announced the resizing of its dividend to a quarterly dividend of $0.18 per common share (or $0.72 per common share on an annualized basis) to align with our growth and financial objectives.

### C. Sundance Unit 6 Agreement

On Feb. 19, 2014, TransAlta reached an agreement with the PPA Buyer related to the dispute on Sundance Unit 6. The Corporation does not expect any material impact to the financial statements as a result of the agreement.

### D. Keephills Unit 2

On Jan. 31, 2014, an outage has commenced on Unit 2 of the Corporation's Keephills facility to perform a rewind of the generator stator as a result of the generator event in 2013 at Keephills Unit 1. The Corporation gave notice of a High Impact Low Probability event and claimed force majeure relief under the PPA.

### E. Fort McMurray Transmission Project

On Jan. 17, 2014, the Corporation announced that the strategic partnership with MidAmerican Transmission, TAMA Transmission, which was formed on May 9, 2013, successfully qualified to participate as a proponent in the Fort McMurray West 500 kilovolt Transmission Project. The Alberta Electric System Operator announced its selection of a short-list of companies, identifying that TAMA Transmission will participate in the next stage of its competitive process for the project.

### F. Australia Natural Gas Pipeline

On Jan. 15, 2014, the Corporation announced that, through a wholly owned subsidiary, an unincorporated joint venture named Fortescue River Gas Pipeline was formed, of which the Corporation has a 43 per cent interest. The first project of the new joint venture will be to build, own, and operate a $178 million natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to the Corporation's Solomon power station.