UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[Check one]

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

OR

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

For the fiscal year ended December 31, 2016 Commission file number 001-15214

TRANSALTA CORPORATION
(Exact name of Registrant as specified in its charter)

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

Canada
(Province or other jurisdiction of incorporation or organization)

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

Not Applicable
(I.R.S Employer Identification Number (if applicable))

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

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

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

Title of each class	Name of each exchange on which registered
Common Shares, no par value	New York Stock Exchange
Common Share Purchase Rights	New York Stock Exchange

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

None

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

Debt Securities

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

x Annual information form x Audited annual financial statements

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

At December 31, 2016, 287,903,467 common shares were issued and outstanding.

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

Yes x No o

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

Yes x No o

INCORPORATION BY REFERENCE

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

Form	Registration No.
S-8	333-72454
S-8	333-101470
F-10	333-215608

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

A. Consolidated Audited Annual Financial Statements

For consolidated audited annual financial statements, including the report of independent chartered accountants with respect thereto, see Exhibit 13.3 incorporated by reference herein.

B. Management's Discussion and Analysis

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

DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the Securities Exchange Act of 1934 ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act are accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure

controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2016, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Management evaluated the effectiveness of our internal control over financial reporting as of December 31, 2016 using the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 framework. Management concluded that our internal control over financial reporting was effective as of December 31, 2016. Certain matters relating to the scope of management's evaluation and limitations of management's conclusions are described below. See "Limitations and Scope of Management's Report on Internal Control over Financial Reporting."

Our independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2016. For Ernst & Young LLP's report see page F3 of the Consolidated Audited Annual Financial Statements for the year ended December 31, 2016 filed as Exhibit 13.3 and incorporated by reference herein, under the heading "Report of Independent Registered Public Accounting Firm".

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

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

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper 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 ("TransAlta" or the "Company") proportionately consolidates the accounts of the Sheerness and Genesee 3 joint arrangements (the "Excluded Entities"), in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these Excluded Entities. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these Excluded Entities. Accordingly, management's evaluation of the Company's internal control over financial reporting did not include an evaluation of the internal controls of any of the Excluded Entities, and management's conclusion regarding the effectiveness of the Company's internal control over financial reporting does not extend to the

internal controls of any of the Excluded Entities.

The 2016 consolidated financial statements of TransAlta, in accordance with EITF 00-1, included CDN$626 million and CDN$592 million of total and net assets, respectively, as of December 31, 2016, and CDN$138 million and CDN$13 million of revenues and net loss, respectively, for the year then ended related to Excluded Entities. Once the financial information is obtained from these Excluded Entities it falls within the scope of TransAlta's internal control framework.

AUDIT COMMITTEE FINANCIAL EXPERT

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

CODE OF ETHICS

TransAlta has adopted a code of ethics as part of its "Corporate Code of Conduct" that applies to all employees and officers which has been filed with the Securities and Exchange Commission. In addition, the Registrant has adopted a code of conduct applicable to all directors of the Company, a separate financial code of conduct which applies to all financial management employees and an Energy Trading code of conduct for our employees working within energy marketing. Our codes of conduct are available on our Internet website at www.transalta.com. There has been no waiver of the codes granted during the 2016 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the years ended December 31, 2016 and December 31, 2015, Ernst & Young LLP and its affiliates were paid $3,083,145 and $3,989,814 respectively, as detailed below:

Ernst & Young LLP

Year Ended Dec. 31		**2016**		**2015**
Audit Fees	$	2,680,186	$	3,549,473
Audit-related fees		363,959		440,341
Tax fees		39,000		0
All other fees		0		0
Total	**$**	**3,083,145**	**$**	**3,989,814**

All amounts are in Canadian dollars unless otherwise stated.

No other audit firms provided audit services in 2016 or 2015.

The nature of each category of fees is described below:

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of our annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English to French of our financial statements and other documents. Total audit fees for 2016 include payments of $1,384,384 related to 2015 and total audit fees for 2015 include payments related to 2014 in the amount of $1,607,423.

Audit-Related Fees

The audit-related fees in 2016 were primarily for work performed by Ernst & Young LLP in relation to compliance and regulatory reporting and miscellaneous accounting advice provided to the Company. The audit-related fees in 2015 were primarily for work performed by Ernst & Young LLP in relation to compliance and regulatory reporting, debt issuances, the issuance of an economic interest in certain assets owned by the Company to TransAlta Renewables Inc. and miscellaneous accounting advice provided to the Company.

Tax Fees

The tax fees for 2016 relate to various tax related matters in our domestic and foreign operations.

All Other Fees

Nil.

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the ARC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act of 2002. This policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting.

Percentage of Services Approved by the ARC

For the year ended December 31, 2015, none of the services described above were approved by the ARC pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

OFF-BALANCE SHEET ARRANGEMENTS

TransAlta currently has no off-balance sheet arrangements. See page M57 of Exhibit 13.2, incorporated by reference herein under the heading "Unconsolidated Structured Entities or Arrangements".

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page M29 of Exhibit 13.2, incorporated by reference herein, under the heading "Capital Structure" and page F89 under the heading "Commitments and Contingencies" of Exhibit 13.3, all incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

We have a separately-designated standing ARC made up of independent directors. The members of the ARC are:

Alan J. Fohrer (Chair)
John P. Dielwart
Timothy W. Faithfull
Yakout Mansour
Beverlee F. Park

MINE SAFETY

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act is included in Exhibit 13.1, incorporated herein, under the heading "Business of TransAlta – U.S. Coal Business Segment".

FORWARD-LOOKING INFORMATION

This Form 40-F, the documents incorporated herein by reference, and other reports and filings of the Company made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on assumptions relating to information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "could", "would", "shall", "believe", "expect",

“estimate”, “anticipate”, “intend”, “plan”, “forecast” “foresee”, “potential”, “enable”, “continue” or other comparable terminology. These statements are not guarantees of TransAlta’s future performance and are subject to risks, uncertainties and other important factors that could cause its actual performance to be materially different from that projected.

In particular, this Form 40-F contains forward-looking statements pertaining to the Company’s business and anticipated future financial performance; TransAlta’s success in executing on our growth projects; the timing and the completion and commissioning of projects under development, including major projects such as the South Hedland Power Project, and their attendant costs; the Company’s estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs, including expectations about the cost savings; the impact of certain hedges on future earnings and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of TransAlta’s capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on the Company and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected settlement of regulatory investigations and disputes; TransAlta’s trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in the Company’s markets; TransAlta’s expectations relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to

the U.S. and other currencies in locations where the Company does business; the monitoring of the Company’s exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; TransAlta’s credit practices; and the estimated contribution of the Energy Marketing business segment to gross margin.

Factors that may adversely impact the Company’s forward-looking statements include risks relating to: fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; demand for electricity and TransAlta’s ability to contract its generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which the Company operates; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving TransAlta’s facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water or wind required to operate the Company’s facilities; natural and man-made disasters; the threat of domestic terrorism and cyberattacks; equipment failure and TransAlta’s ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; the Company’s provision for income taxes; legal, regulatory, and contractual proceedings involving the Company; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; and development projects and acquisitions, including delays in the construction and commissioning of the South Hedland Power Project. The foregoing risk factors, among others, are described in further detail under the heading “Risk Factors” in the Annual Information Form and in the documents incorporated by reference in the Annual Information Form, including TransAlta’s Management’s Discussion and Analysis for the year ended December 31, 2016.

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

DOCUMENTS FILED AS PART OF THIS REPORT AND EXHIBITS

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

13.1 TransAlta Corporation Annual Information Form for the year ended December 31, 2016.

13.2	Management's Discussion and Analysis for the year ended December 31, 2016.
13.3	Consolidated Audited Annual Financial Statements for the year ended December 31, 2016.
13.4	Management's Annual Report on Internal Control over Financial Reporting, (included on page F2 of Exhibit 13.3 filed herewith).
13.5	Independent Auditors' Report of Registered Public Accounting Firm, (included on page F4 of Exhibit 13.3 filed herewith).
23.1	Consent of Ernst & Young LLP Chartered Accountants.
31.1	Certification of President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of President and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

UNDERTAKING

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

CONSENT TO SERVICES OF PROCESS

The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises. Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

SIGNATURES

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

TRANSALTA CORPORATION

/s/ Donald Tremblay
Donald Tremblay
Chief Financial Officer

Dated: March 3, 2017

EXHIBIT INDEX

13.1	TransAlta Corporation Annual Information Form for the year ended December 31, 2016.
13.2	Management's Discussion and Analysis for the year ended December 31, 2016
13.3	Consolidated Audited Annual Financial Statements for the year ended December 31, 2016.
13.4	Management's Annual Report on Internal Control over Financial Reporting, (included on page F2 of Exhibit 13.3 filed herewith).

13.5	Independent Auditors' Report of Registered Public Accounting Firm, (included on page F4 of Exhibit 13.3 filed herewith).
23.1	Consent of Ernst & Young LLP Chartered Accountants.
31.1	Certification of President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of President and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.



TRANSALTA CORPORATION

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

March 2, 2017

TABLE OF CONTENTS

PRESENTATION OF INFORMATION	2
SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS	2
DOCUMENTS INCORPORATED BY REFERENCE	3
CORPORATE STRUCTURE	3
OVERVIEW	5
GENERAL DEVELOPMENT OF THE BUSINESS	6
BUSINESS OF TRANSALTA	14
CANADIAN COAL BUSINESS SEGMENT	14
CANADIAN GAS BUSINESS SEGMENT	15
AUSTRALIAN GAS BUSINESS SEGMENT	17
HYDRO BUSINESS SEGMENT	18
WIND AND SOLAR BUSINESS SEGMENT	21
U.S. COAL BUSINESS SEGMENT	24
ENERGY MARKETING SEGMENT	26
CORPORATE SEGMENT	26
NON-CONTROLLING INTERESTS	26
PPAS	27
COMPETITIVE ENVIRONMENT	29
REGULATORY FRAMEWORK	31
COMPETITIVE STRENGTHS	32
ENVIRONMENTAL RISK MANAGEMENT	33
ONGOING AND RECENTLY PASSED ENVIRONMENTAL LEGISLATION	33
TRANSALTA ACTIVITIES	36
RISK FACTORS	38
EMPLOYEES	51
CAPITAL STRUCTURE	51
COMMON SHARES	51
FIRST PREFERRED SHARES	51
CREDIT RATINGS	58
DIVIDENDS	61
COMMON SHARES	61
PREFERRED SHARES	62
MARKET FOR SECURITIES	64
COMMON SHARES	64
PREFERRED SHARES	65
DIRECTORS AND OFFICERS	70
INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	80
INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS	80
CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS	80
CONFLICTS OF INTEREST	81
LEGAL PROCEEDINGS AND REGULATORY ACTIONS	81
TRANSFER AGENT AND REGISTRAR	81

INTERESTS OF EXPERTS 81
ADDITIONAL INFORMATION 81
AUDIT AND RISK COMMITTEE 82
AUDIT AND RISK COMMITTEE CHARTER A-1
GLOSSARY OF TERMS B-1

PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this annual information form ("Annual Information Form" or "AIF") is given as at or for the year ended December 31, 2016. All dollar amounts are in Canadian dollars unless otherwise noted. Unless the context otherwise requires, all references to the "Corporation" and to "TransAlta", "we", "our" and "us" herein refer to TransAlta Corporation and its subsidiaries, including TransAlta Renewables Inc., on a consolidated basis. Reference to "TransAlta Corporation" herein refers to TransAlta Corporation, excluding its subsidiaries. Capitalized terms not defined in the body of this AIF shall have their respective meanings set forth in Appendix "B" – Glossary of Terms hereto.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form, the documents incorporated herein by reference, and other reports and filings of the Corporation made with the securities regulatory authorities, include forward-looking statements. All forward-looking statements are based on assumptions relating to information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast" "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this Annual Information Form contains forward-looking statements pertaining to our business and anticipated future financial performance; our success in executing on our growth projects; the timing and the completion of growth projects, including major projects such as the South Hedland Power Project and the Brazeau Pumped Storage Project and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the conversion of our coal fired units to natural gas; the impact of certain hedges on future earnings and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, including the change to a capacity market in Alberta and the continued implementation of the Alberta Climate Leadership Plan, and their expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected settlement of regulatory investigations and disputes; our trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations relating to the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; and the estimated contribution of the Energy Marketing business segment to gross margin.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; demand for electricity and our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water or wind required to operate our facilities; natural and man-made disasters; the threat of domestic terrorism and cyberattacks; equipment failure

and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; and development projects and acquisitions, including delays in the construction and commissioning of the South Hedland Power Project. The foregoing risk factors, among others, are described in further detail under the heading "Risk Factors" in this Annual Information Form and in the documents incorporated by reference in this Annual Information Form, including our Management's Discussion and Analysis for the year ended December 31, 2016 (the "Annual MD&A").

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

DOCUMENTS INCORPORATED BY REFERENCE

TransAlta's audited consolidated financial statements for the year ended December 31, 2016 and related annual management's discussion and analysis are hereby specifically incorporated by reference in this AIF. Copies of these documents are available on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

CORPORATE STRUCTURE

Name and Incorporation

TransAlta Corporation was formed by Certificate of Amalgamation issued under the *Canada Business Corporations Act* (the "CBCA") on October 8, 1992. On December 31, 1992, a Certificate of Amendment was issued in connection with a plan of arrangement involving TransAlta Corporation and TransAlta Utilities Corporation ("TransAlta Utilities" or "TAU") under the CBCA. The plan of arrangement, which was approved by shareholders on November 26, 1992, resulted in common shareholders of TransAlta Utilities exchanging their common shares for shares of TransAlta Corporation on a one for one basis. Upon completion of the arrangement, TransAlta Utilities became a wholly owned subsidiary of TransAlta Corporation.

Effective January 1, 2009, TransAlta completed a reorganization, whereby the assets and business affairs of TAU and TransAlta Energy Corporation ("TransAlta Energy" or "TEC") (with the exception of the wind business) were transferred to TransAlta Generation Partnership, a new Alberta general partnership, whose partners are TransAlta Corporation and TransAlta Generation Ltd., a wholly owned subsidiary of TransAlta Corporation. TransAlta Generation Partnership is managed by TransAlta Corporation pursuant to the terms of the partnership agreement and a management services agreement.

Immediately following the transfer of assets by TAU and TEC to TransAlta Generation Partnership, TransAlta Corporation amalgamated with TAU, TEC, and Keephills 3 GP Ltd. pursuant to the provisions of the CBCA.

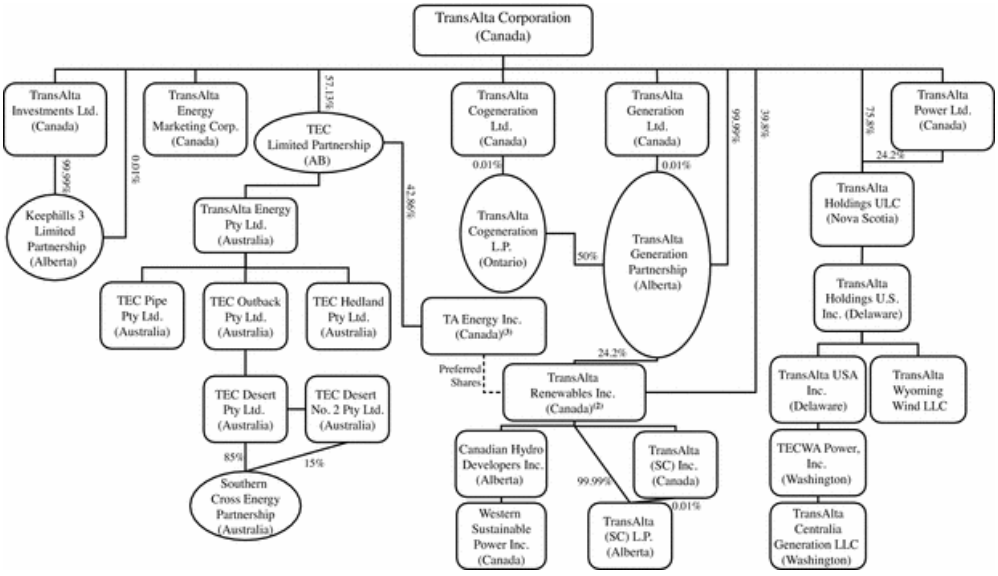
On November 4, 2009, TransAlta completed its acquisition of Canadian Hydro Developers, Inc.

On December 7, 2010, TransAlta amended its articles to create the Series A Shares and Series B Shares; again on November 23, 2011 to create the Series C Shares and Series D Shares; again on August 3, 2012 to create the Series E Shares and Series F Shares; and then again on August 13, 2014 to create the Series G Shares and Series H Shares.

In August 2013, TransAlta Renewables Inc. ("TransAlta Renewables") completed its initial public offering. In connection with the offering, TransAlta Corporation transferred to TransAlta Renewables certain wind and hydro power generation assets previously held directly or indirectly by TransAlta Corporation. TransAlta Corporation provides all management, administrative and operational services required for TransAlta Renewables to operate and administer its assets and to acquire additional assets. As of the date of this Annual Information Form, TransAlta Corporation owned, directly and indirectly, approximately 64 per cent of the outstanding voting equity in TransAlta Renewables.

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

As at the date of this AIF, the principal subsidiaries of TransAlta Corporation and their respective jurisdictions of formation are set out below (1):



Notes:

(1) Unless otherwise stated, ownership is 100 per cent.

(2) We own, directly and indirectly, an aggregate interest of approximately 64 per cent of TransAlta Renewables (including Class B share ownership), which includes 39.8 per cent through direct ownership and 24.2 per cent through TransAlta Generation Partnership. The remaining 36 per cent interest in TransAlta Renewables is publicly owned.

(3) The remaining 1.56% of TA Energy Inc. is indirectly owned by TransAlta through its holding in Kenwind Energy Inc. (Canada).

OVERVIEW

TransAlta and its predecessors have been engaged in the production and sale of electric energy since 1909. We are among Canada's largest non-regulated electricity generation and energy marketing companies with an aggregate net ownership interest of 8,716 megawatts ("MW") of generating capacity[1][2]. We operate facilities having approximately 10,202 MW of aggregate generating capacity. In addition, we are in the process of constructing a 150 MW combined cycle power station near South Hedland, Western Australia which output is included in the numbers above. We are focused on generating and marketing electricity in Canada, the United States and Western Australia through our diversified portfolio of facilities fuelled by coal, natural gas, diesel, hydro, wind and solar.

The Canadian Coal segment has a net ownership interest of approximately 3,593 MW of electrical generating capacity. All of the facilities in this segment are located in Alberta.

The U.S. Coal segment holds our Centralia thermal plant, which represents a net ownership interest of 1,340 MW of electrical generating capacity.

The Hydro segment has a net ownership interest of approximately 926 MW of electrical generating capacity. The facilities that comprise this segment are predominantly located in Alberta, B.C., and Ontario.

The Wind and Solar segment has a net ownership interest of approximately 1,384 MW of electrical generating capacity and includes facilities located in Alberta, Ontario, New Brunswick, Quebec, Wyoming, Massachusetts, and Minnesota.

The Canadian Gas segment has a net ownership interest of approximately 898 MW of electrical generating capacity and includes facilities held in Alberta and Ontario.

The Australian Gas segment has a net ownership interest of approximately 575 MW of electrical generating capacity including our 150 MW South Hedland gas plant which is currently being constructed.

We regularly review our operations in order to optimize our generating assets and evaluate appropriate growth opportunities to maximize value to the Corporation. We have in the past, and may in the future, make changes and additions to our fleet of coal, natural gas, hydro, wind and solar fuelled facilities.

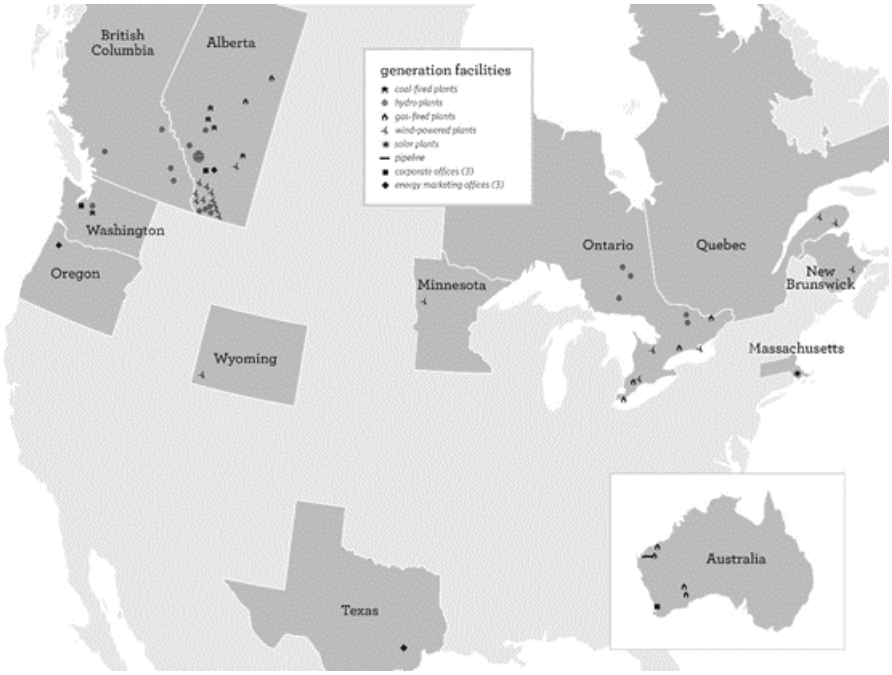
In August, 2013, TransAlta Renewables completed its initial public offering of its common shares. TransAlta Corporation is the majority owner of TransAlta Renewables, with an approximate 64 per cent direct and indirect ownership interest as of the date of this Annual Information Form. TransAlta Renewables is one of the largest generators of wind power and among the largest publicly traded renewable power generation companies in Canada.

(1) The net ownership interest of 8,716 MW includes 100 per cent of the generating capacity of TransAlta Renewables. All references to "net ownership interest" in this Annual Information Form include 100 per cent of the generating capacity of TransAlta Renewables. As of the date of this Annual Information Form, TransAlta owns an approximate 64 per cent direct and indirect ownership interest in TransAlta Renewables.

(2) MW information provided as of December 31, 2016.

TransAlta's Map of Operations

The following map outlines TransAlta's operations as of December 31, 2016.



GENERAL DEVELOPMENT OF THE BUSINESS

TransAlta is organized into eight business segments: Canadian Coal, U.S. Coal, Canadian Gas, Australian Gas, Wind and Solar, Hydro, Energy Marketing and Corporate. The Canadian Coal, U.S. Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro segments are responsible for constructing, operating and maintaining our electrical generation. The Canadian Coal segment is also responsible for the operation and maintenance of our related mining operations in Canada. The Energy Marketing segment is responsible for marketing our production through short-term and long-term contracts, for securing cost effective and reliable fuel supply, and for maximizing margins by optimizing our assets as market conditions change. In addition to serving our assets, our marketing team actively markets energy products and services to energy producers and customers. This segment also encompasses the management of available generating capacity as well as the fuel and transmission needs of the generation businesses. All the segments are supported by a Corporate segment which includes the Corporation's central financial, legal, administrative, and investing functions.

The significant events and conditions affecting our business during the three most recently completed financial years are summarized below. Certain of these events and conditions are discussed in greater detail under the heading "*Business of TransAlta*" in this AIF.

Recent Developments

2017

Sale of Interest in Wintering Hills Facility

On January 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. Proceeds from the sale will be used for general corporate purposes, including to reduce debt and to fund future renewables growth, including potential contracted renewable opportunities in Alberta. The transaction closed on March 1, 2017.

Generation and Business Development

2016

Mississauga Recontracting

On December 22, 2016, we signed a Non-Utility Generator (NUG) Enhanced Dispatch Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator ("IESO") for our Mississauga Cogeneration Facility (the "Mississauga Facility"). The NUG Contract came into effect on January 1, 2017. In conjunction with the execution of the NUG Contract, we terminated, effective December 31, 2016, the Mississauga Facility's existing contract with the Ontario Electricity Financial Corporation ("OEFC"), which would have otherwise terminated in December 2018.

TransAlta Reaches Agreement with the Government of Alberta

On November 24, 2016, we entered into an agreement (the "Off-Coal Agreement") with the Government of Alberta on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before December 31, 2030. Under the terms of the Off-Coal Agreement, we will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to terms and conditions including the cessation of all coal-fired emissions in 2030. Other conditions include maintaining prescribed spending on investment and investment related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), maintaining spending on programs and initiatives to support the communities surrounding the plants and

the employees of the Corporation negatively impacted by the phase-out of coal generation, and the fulfillment of all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal.

Additionally, we announced that we reached an understanding with the Government of Alberta pursuant to a Memorandum of Understanding to collaborate and cooperate in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the Province of Alberta.

Favourable Keephills 1 *Force Majeure* Ruling

On November 18, 2016, an independent arbitration panel confirmed that we were entitled to *force majeure* relief for the 2013 Keephills 1 forced outage. Our 395 MW Keephills 1 facility tripped off-line on March 5, 2013 due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined a full rewind of the generator stator was required. The unit returned to service on October 6, 2013.

Decommissioning of Cowley Ridge

In February 2016, Cowley Ridge reached the end of its operating life and was decommissioned. Cowley Ridge, which began operating in 1993, was the first and oldest wind facility in Canada. Cowley Ridge had maximum capacity of 16 MW of renewable energy at its time of decommissioning.

2015

Parkeston Recontracting

During the last quarter of 2015, we executed an extension to the power purchase agreement to supply power to the Kalgoorlie Consolidated Gold Mine from the 55MW share of the Parkeston power station. The agreement extends the previous contract to October 2026 with options for early termination available to either party beginning in 2021. The risks associated with the extended power purchase agreement remain consistent with the original contract. The contract extension will continue to provide stable cash flow for the business.

Restructured Poplar Creek Contract and Acquisition of Two Wind Farms

On August 31, 2015, we restructured our prior arrangement with Suncor Energy ("Suncor") in respect of its power generation operations near Fort McMurray. As part of the contract restructuring we acquired Suncor's interest in two wind projects located in Alberta and Ontario.

Under the terms of the new arrangement, Suncor acquired from us two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the co-generation facility and will have the right to use the full 244 MW of capacity of our gas generators until 2030. We continue to provide Suncor with centralized monitoring, diagnostics and technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek co-generation facility will transfer to Suncor in 2030.

As part of the transaction, we acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and a 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta. We subsequently sold our interest in Wintering Hills on March 1, 2017. See "*Business of TransAlta – Recent Developments*" in this AIF.

Sundance Unit 7

During 2015, we received approval from the AUC to construct and operate an 856 MW combined-cycle natural-gas-fired power plant in Alberta. The Sundance 7 project has received all regulatory approvals after receiving the Environmental Protection and Enhancement Act approval from Alberta Environment and Parks on October 1, 2015. Construction of Sundance 7 will not commence until we have contracted a significant portion of the plant capacity. Following changes to market conditions in Alberta during the last few years, we do not anticipate that this condition will be met before the next decade. In December 2015, we repurchased our partner's 50 per cent share in TransAlta MidAmerican Partnership ("TAMA Power"), the jointly controlled entity developing this project, for consideration of $10 million payable over five years, along with an option permitting the partner to buy back into this project or into other projects of TAMA Power during this period.

Community Development, Energy Efficiency Investment

On July 30, 2015, we announced that we were moving ahead with plans to invest $55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The initiative is part of TransAlta Centralia's transition from coal-fired operations in Washington, beginning in December 31, 2020.

The U.S.$55 million community investment is part of the TransAlta Energy Transition Bill, passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State, closing the Centralia facility's two units, one in 2020 and the other in 2025. Approved funding for community investment included approximately U.S.$1.1 million incurred as at December 31, 2016.

Acquisition of Long-Term Contracted Solar and Wind Assets

On July 27, 2015, we announced the acquisition of 71 MW of long-term contracted renewable generation assets for a purchase price of US$75.8 million, together with the assumption of certain tax equity obligations and US$41.8 million of non-recourse project debt. The assets acquired include 21 MW of solar projects located in Massachusetts and a 50 MW wind facility in Minnesota. The assets are contracted under long-term power purchase agreements ranging from 20 to 30 years with several high quality counterparties.

This acquisition of the solar projects closed on September 1, 2015 and the acquisition of the wind facility closed on October 1, 2015.

Completion of Natural Gas Pipeline in Australia

On March 19, 2015, TransAlta's joint venture partner DBP Development Group (a wholly owned subsidiary of DUET Group), announced the completion of the Fortescue River Gas Pipeline in Western Australia. The project, TransAlta's first pipeline, was completed within a nine month timeframe and for an estimated total cost of AUD$183 million. It delivers gas to our Solomon power station which services Fortescue Metals Group's mining operations at the Solomon Hub. The power station now operates on natural gas improving reliability and efficiency.

Keephills 1 *Force Majeure*

On March 17, 2015, an unplanned outage began at our 395 MW Keephills Unit 1 facility due to a damaged superheater. The unit returned to service on May 17, 2015. Following the establishment of the plan to return the unit to service and the review of the causes of the outage, we gave notice under the Alberta PPA to the buyer and the Balancing Pool of a "High Impact Low Probability" *force majeure* event. A *force majeure* event under the Alberta PPA entitles us to continue to receive our Alberta PPA capacity payment and exempts us from having to pay availability penalties.

Windsor Recontracting

During the first quarter of 2015, we executed a new 15-year power supply contract with the IESO for our Windsor facility, which became effective December 1, 2016. Under this new contract, the Windsor plant is dispatchable for up to 72 MW of capacity.

2014

Major Maintenance Agreement

On November 14, 2014, we entered into an agreement with Alstom Power Canada Inc. ("Alstom") to provide major maintenance at our Alberta coal facilities. The agreement relates to ten major maintenance projects at our Keephills and Sundance plants.

South Hedland Power Project

On July 28, 2014, we announced that we had agreed to build, own, and operate a 150 MW combined cycle gas power station in South Hedland, Western Australia to supply power to Regional Power Corporation trading as Horizon Power ("Horizon Power"), a state owned utility, and to the Pilbara Infrastructure Pty Ltd., a wholly owned subsidiary of Fortescue Metals Group ("Fortescue"). The project is estimated to cost approximately AUD $570 million which includes the cost of acquiring existing equipment from Horizon Power. The project is being built on an existing site at Boodarie Industrial Estate and is anticipated to be one of the most efficient power stations in the region. The power station will supply Horizon Power's customers in the Pilbara region as well as Fortescue's port operations. IHI Engineering Australia has been selected as the contractor to construct the power station.

We continue to advance the construction of the South Hedland Power Project. Commissioning of the Open Cycle Gas Turbine ("OCGT") was completed and hand over occurred on December 8, 2016. A commercial agreement was executed with Horizon Power to supply electricity generated from the OCGT in the interim. We continue to expect the project to be delivered on schedule and on budget in mid-2017.

TransAlta and Province Reach Agreement on Ghost Reservoir

On June 4, 2014, we announced that we had reached an agreement with the Alberta Government regarding modifying the operations of the Ghost Reservoir to provide part of a solution for flood mitigation. The revised operating pattern of the Ghost Reservoir involved holding the reservoir near its minimum low water level until July 31, 2014, approximately six weeks longer than the prior operating pattern. Following the success of this flood mitigation agreement in 2014, a similar agreement that provided increased flood storage was entered into for 2015. In 2016, we signed a five-year agreement with the Government of Alberta to aid in potential flood and drought mitigation efforts.

Sundance Unit 6 Agreement

On August 18, 2011, the Sundance Unit 6 Generator Step-Up Transformer was damaged as a result of a fire. We gave notice and claimed *force majeure* relief under the Alberta PPA. During the third quarter of 2012, the Alberta PPA buyer informed us that they will be taking the matter to arbitration. On February 19, 2014, we reached an agreement with the Alberta PPA buyer related to this Sundance Unit 6 dispute.

Keephills Unit 2

On January 31, 2014, an outage commenced at Unit 2 of our Keephills facility to perform a rewind of the generator stator which arose due to the generator event at Keephills Unit 1 facility in 2013. We gave notice of a High Impact Low Probability ("HILP") event and claimed *force majeure* relief under the Alberta PPA. The matter was disputed by the buyer and is currently sitting in abeyance.

Fort McMurray Transmission Project

On January 17, 2014, we announced that our strategic partnership with MidAmerican Transmission, TAMA 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. TAMA Transmission submitted its bid and in December 2014, after completing its review of all bid submissions, the Alberta Electric System Operator ("AESO") notified TAMA Transmission that the contract had been awarded to a competitor.

Australia Natural Gas Pipeline

On January 15, 2014, we announced that, through a wholly owned subsidiary, an unincorporated joint venture named Fortescue River Gas Pipeline was formed, of which we have a 43 per cent interest. The first project of the new joint venture was to build, own, and operate an AUD$183 million natural gas pipeline from the Dampier to Bunbury Natural Gas Pipeline to our Solomon power station. The pipeline was completed on March 19, 2015.

Corporate and Energy Marketing

2016

Poplar Creek Financing

On December 7, 2016, we completed a $202.5 million bond offering on behalf of our indirect wholly-owned subsidiary, TAPC Holdings LP ("TAPC"), which is secured by the equity interests in the Issuer and its general partner, and a first ranking charge over all of TAPC's accounts and certain other assets. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points. Proceeds were used to provide financing to certain of TAPC's affiliates, reduce the indebtedness of certain of TAPC's affiliates (including the Corporation) and for other general business purposes.

Quebec Wind Asset Project Financing

On June 3, 2016, TransAlta Renewables completed a $159 million bond offering on behalf of its indirect wholly-owned subsidiary, New Richmond Wind L.P. ("NR Wind"), which is secured by a first ranking charge over all assets of NR Wind. The bonds are amortizing and bear interest from their date of issue at a rate of 3.963%, payable semi-annually and mature on June 30, 2032. Proceeds were used to make advances to Canadian Hydro Developers, Inc. on a subordinated basis pursuant to an intercompany loan agreement, the proceeds of which were used to finance certain facilities of NR Wind's affiliates and for other general business purposes.

Listing of Series B Preferred Shares

On March 31, 2016, 1,824,620 of our 12,000,000 cumulative redeemable rate reset first preferred shares, Series A (the "Series A Shares") were converted, on a one-for-one basis, into cumulative redeemable floating rate first preferred shares, Series B (the "Series B Shares"). As a result of the conversion, TransAlta has 10,175,380 Series A Shares and 1,824,620 Series B Shares issued and outstanding.

Dividend Resizing and Dividend Reinvestment Program Suspension

On January 14, 2016, to support the Corporation's transition from coal to gas-fired and renewable power generation in the province of Alberta and to maximize the Corporation's financial flexibility, we announced the resizing of our dividend to $0.16 per share on an annualized basis and the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan.

Closing of $540 Million Transaction with TransAlta Renewables

On January 6, 2016, we announced the closing of the investment by TransAlta Renewables in the Corporation's Sarnia cogeneration plant, Le Nordais wind farm and Ragged Chute hydro facility (the "Canadian Assets") for a combined value of $540 million. The Canadian Assets consist of approximately 611 MW of contracted power generation assets located in Ontario and Quebec. The Corporation received cash proceeds of $172.5 million, a $215 million convertible unsecured subordinated debenture and approximately $152.5 million in common shares in the capital of TransAlta Renewables. The cash proceeds were used to reduce corporate debt.

2015

Moody's Credit Rating Downgrade

On December 17, 2015, Moody's Investor Services ("Moody's") announced that it was downgrading TransAlta Corporation's credit rating. The Corporation's outlook is stable. See "*Credit Ratings*" in this AIF.

AIMCo's Purchase of Common Shares in TransAlta Renewables

On November 23, 2015 we announced that we had entered into an agreement with Alberta Investment Management Corporation ("AIMCo") for the sale of $200 million of common shares of TransAlta Renewables ("AIMCo Investment") at a price per share equal to $9.75. The AIMCo Investment closed on November 26, 2015.

Ontario Wind Assets Project Financing

On October 1, 2015, TransAlta Renewables completed a $442 million bond offering on behalf of its indirect wholly-owned subsidiary, Melancthon Wolfe Wind LP, which was secured by a first ranking charge over all assets of the indirect wholly-owned subsidiary. The bonds are non-recourse to TransAlta, and bear interest at an annual fixed interest rate of 3.8 per cent, payable semi-annually and mature on December 31, 2028. Proceeds were used to make advances to Canadian Hydro Developers, Inc. on a subordinated basis pursuant to an intercompany loan agreement and for other general corporate purposes of TransAlta Renewables.

Agreement with Market Surveillance Administrator

On September 30, 2015, we advised that we had reached an agreement with the Market Surveillance Administrator (the "MSA") to settle all outstanding proceedings before the Alberta Utilities Commission (the "AUC"). The proceedings pertained to allegations that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. The AUC approved the settlement on October 29, 2015. Under the terms of the agreement, we paid a total amount of $56 million, including approximately $27 million as a repayment of "economic benefit" under the legislation, $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. The first payment of $31 million was made on November 29, 2015 and the final payment was made in the fourth quarter of 2016.

Cost Savings Through Position Eliminations, Efficiency and Productivity Initiatives

On September 29, 2015, we announced further staff reductions to continue to focus on improving our competitive position and meeting the needs of our customers in a dynamic economic environment. The total number of position reductions throughout the Corporation in 2015, including position reductions that were achieved through lay-offs, attrition and a hiring freeze, was 486.

$1.78 Billion Transaction with TransAlta Renewables

On May 7, 2015, we announced the closing of the acquisition by TransAlta Renewables of an economic interest based on the cash flows of our Australian assets (the "Australian Transaction"). The portfolio, held by TransAlta Energy (Australia) Pty Ltd, consists of six operating assets with an installed capacity of 425 MW, the 150 MW South Hedland project currently under construction, as well as a 270 km gas pipeline. The combined value of the Australian Transaction was approximately $1.78 billion. The Australian Transaction was originally announced on March 23, 2015.

At the closing of the Australian Transaction, TransAlta Renewables paid us $216.9 million in cash as well as approximately $1,067 million through the issuance of a combination of common shares and Class B shares in the capital of TransAlta Renewables. Cash proceeds from the Australian Transaction were used to reduce indebtedness and strengthen our balance sheet, providing greater financial flexibility for future growth opportunities.

Issuance of Bond

On February 11, 2015, the Corporation and its project level partner issued a bond secured by their jointly owned Pingston facility. Our share of gross proceeds was $45 million. The bond bears interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million secured debenture bearing interest at 5.28 per cent.

Investment Grade Credit Rating from Fitch Ratings

On January 8, 2015, we announced that Fitch Ratings ("Fitch") has rated our debt securities. See " *Credit Ratings*" in this AIF.

2014

Board of Director Appointments

During the third quarter of 2014, we announced that Mr. P. Thomas Jenkins, OC, CD and Mr. John P. Dielwart had been appointed to our Board of Directors ("Board"), effective September 1, 2014 and October 1, 2014, respectively. The appointments are the result of our ongoing process of evaluating the skills and composition of the Board, planning for succession and aligning the skills of the Board with the strategic direction of the Corporation.

Sale of Preferred Shares

On August 15, 2014, we completed a public offering of 6.6 million Series G 5.3 per cent Cumulative Redeemable Rate Reset First Preferred Shares, for aggregate gross proceeds of $165 million. The proceeds from the offering were used for general corporate purposes in support of our business, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation.

Senior Note Offering

On June 3, 2014, we completed an offering of U.S.$400 million aggregate principal amount of senior notes maturing in 2017 and bearing interest at 1.90 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

California Claim

On May 30, 2014, we announced that our settlement with California utilities, the California Attorney General and certain other parties (the "California Parties") to resolve claims related to the 2000 to 2001 power crisis in the State of California had been approved by the U.S. Federal Energy Regulatory Commission ("FERC"). The settlement provided for the payment by us of U.S.$52 million in two equal payments and a credit of approximately U.S.$97 million for monies owed to us from accounts receivable. The first payment of U.S.$26 million was paid in 2014 and the second payment was made in 2015.

Secondary Offering of TransAlta Renewables Common Shares

On April 29, 2014, we completed a secondary offering of an aggregate of 11,950,000 common shares which we held directly and indirectly in TransAlta Renewables at a price of $11.40 per Common Share, resulting in gross proceeds to the Corporation of $136.2 million. The net proceeds from the offering were

used for general corporate purposes, including the funding of capital projects and the reduction of indebtedness of the Corporation.

Executive Leadership Team Appointments

On March 18, 2014, we announced three senior leadership appointments that enhanced our objectives of operational excellence from the base business and growth. Brett Gellner was appointed to the role of Chief Investment Officer, responsible for leading all growth aspects of the Corporation. Donald Tremblay joined TransAlta as Chief Financial Officer, effective March 31, 2014, and on July 3, 2014, Wayne Collins joined TransAlta as Executive Vice President, Coal and Mining Operations.

CE Generation Sale

On February 20, 2014, we announced the sale of our 50 per cent interest in CE Generation, the Blackrock development project ("Blackrock") and Wailuku Holding Company, LLC ("Wailuku") to MidAmerican Renewables for proceeds of U.S.$193.5 million.

MidAmerican Renewables held the other 50 per cent interest in CE Generation, Blackrock and Wailuku. The sale of our interest in CE Generation and Blackrock closed on June 12, 2014 and the sale of our 50 per cent interest in Wailuku closed on November 25, 2014.

Dividend

On February 20, 2014, we announced the resizing of our 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. On January 14, 2016, we announced the further resizing of our dividend to a quarterly dividend of $0.04 per common share (or $0.16 per common share on an annualized basis).

BUSINESS OF TRANSALTA

Our Canadian Coal, U.S. Coal, Wind and Solar, Hydro, Canadian Gas and Australian Gas business segments are responsible for constructing, operating and maintaining our electrical generation facilities as well as the related mining operations in Canada and the U.S. The Energy Marketing segment is responsible for marketing our production and securing cost effective and reliable fuel supply. All the segments are supported by a Corporate segment.

The following table identifies each business segment's contribution to revenues:

	2016 Revenues	2015 Revenues
Canadian Coal	44%	40%
U.S. Coal	15%	17%
Canadian Gas	17%	20%
Australian Gas	5%	5%
Wind and Solar	11%	11%
Hydro	5%	5%
Energy Marketing	3%	2%
Corporate	0%	0%

For further information on TransAlta's segment earnings and assets, please refer to Note 33 of our audited consolidated financial statements for the year ended December 31, 2016, which financial statements are incorporated by reference herein. See "*Documents Incorporated by Reference*" in this AIF.

The following sections of this Annual Information Form provide detailed information on facilities by geographic location and fuel type.

Canadian Coal Business Segment

The following table summarizes our Canadian Coal generation facilities:

Facility Name	Province	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Genesee 3	AB	50	233	2005	Merchant	-
Keephills Unit No. 1[3]	AB	100	395	1983	Alberta PPA/Merchant	2020
Keephills Unit No. 2[3]	AB	100	395	1984	Alberta PPA/Merchant	2020
Keephills Unit No. 3	AB	50	232	2011	Merchant	-
Sheerness Unit No. 1[4]	AB	25	100	1986	Alberta PPA/Merchant	2020
Sheerness Unit No. 2	AB	25	98	1990	Alberta PPA	2020
Sundance Unit No. 1	AB	100	280	1970	Alberta PPA	2017
Sundance Unit No. 2	AB	100	280	1973	Alberta PPA	2017
Sundance Unit No. 3[5]	AB	100	368	1976	Alberta PPA/Merchant	2020
Sundance Unit No. 4[5]	AB	100	406	1977	Alberta PPA/Merchant	2020
Sundance Unit No. 5[5]	AB	100	406	1978	Alberta PPA/Merchant	2020
Sundance Unit No. 6[5]	AB	100	401	1980	Alberta PPA/Merchant	2020
Total Canadian Coal Net Capacity			**3,593**			

Notes:

(1) MW are rounded to the nearest whole number. Column may not add due to rounding.
(2) Where no contract expiry date is indicated, the facility operates as merchant.
(3) Merchant capacity includes a 12 MW uprate on units 1 and 2, which began operation in the second quarter of 2012.
(4) Merchant capacity includes a 10 MW uprate completed in the first quarter of 2016.
(5) Merchant capacity includes uprates of 15 MW, 53 MW, 53 MW and 44 MW on Sundance units 3, 4, 5 and 6, respectively.

Our thermal plants are generally base load plants, meaning that they are expected to operate for long periods of time at or near their rated capacity. The Genesee 3 facility, located approximately 50 kilometres west of Edmonton, Alberta, is jointly owned with Capital Power. Coal for the Genesee 3 facility is provided from the adjacent Genesee mine. The coal reserves of the mine are owned, leased or controlled jointly by Westmoreland Coal Company

("Westmoreland Coal") and Capital Power. We have entered into coal supply agreements with Westmoreland Coal, which operates the mine, to supply coal for the life of the facility.

Keephills 1 and 2 and the Sundance facilities are located approximately 70 kilometres southwest of Edmonton, Alberta, and are both owned by

TransAlta. Keephills unit 1 and unit 2 have a maximum capacity of 395 MW each. The Sheerness facility is located approximately 200 kilometres northeast of Calgary, Alberta and is jointly owned by TA Cogen and ATCO Power (2000) Ltd. ("ATCO Power"). See " *Business of TransAlta – Non-Controlling Interests*" in this AIF.

On November 24, 2016, we entered into the Off-Coal Agreement with the Government of Alberta pertaining to the cessation of coal-fired emissions from the Keephills 3, Genesee 3, and Sheerness coal-fired facilities. The Off-Coal Agreement provides that we will receive cash payments of approximately $37.4 million, net to TransAlta, commencing in 2017 and terminating in 2030, subject to satisfaction of certain terms and conditions including the cessation of all coal-fired emissions in 2030. See "*See General Developments of the Business – Generation and Business Development*" in this AIF.

Fuel requirements for the Western Canadian thermal generation facilities that we operate are supplied by a surface strip coal mine located in close proximity to the facilities. We own the Highvale mine that supplies coal to the Sundance and Keephills facilities and perform the mining, reclamation and associated work at the Highvale mine. PMRL, under contract with TransAlta, operated the mine on our behalf until January 17, 2013. On that date, we assumed operating and management control of the Highvale mine through our wholly-owned subsidiary, SunHills. The decision to directly operate our facility was made in line with our operating model for operational excellence and to provide us with greater control over our costs and operations.

We estimate that the recoverable coal reserves contained in this mine are sufficient to supply the anticipated requirements for the life of the facilities it serves, including those running post Alberta PPA expiry. We also own the Whitewood mine, which formerly supplied coal to the now decommissioned Wabamun facility. The Whitewood mine is no longer in operation and we have completed reclamation of the site.

TransAlta and Capital Power formed a joint venture through which each has a 50 per cent ownership interest of the Keephills 3 facility. Capital Power was responsible for the construction of the facility and TransAlta is responsible for managing the joint venture. Keephills 3 began commercial operations on September 1, 2011. The facility is jointly operated by Capital Power and TransAlta. Each partner independently dispatches and markets its share of the unit's electrical output. We provide the coal fuel to the facility through our Highvale mine.

Coal for the Sheerness facility is provided from the adjacent Sheerness mine. The coal reserves of the mine are owned, leased or controlled jointly by TA Cogen, ATCO Power and Westmoreland Coal. TA Cogen and ATCO Power have entered into coal supply agreements with Westmoreland Coal, which operates the mine, to supply coal until 2026. See "*Business of TransAlta – Non-Controlling Interests*" in this AIF.

Canadian Gas Business Segment

The following table summarizes our natural gas-fired and diesel fired generation facilities:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Fort Saskatchewan [5]	AB	30	35	1999	LTC	2019
Poplar Creek [4]	AB	100	230	2001	LTC	2030
Mississauga [5]	ON	50	54	1992	LTC	2018
Ottawa [5]	ON	50	37	1992	LTC/Merchant	2017-2033
Sarnia [3]	ON	100	506	2003	LTC	2022-2025
Windsor [5]	ON	50	36	1996	LTC/Merchant	2031
Total Cnd Gas Net Capacity			**898**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As of the date of this Annual Information Form, TransAlta owns approximately 64 per cent of the voting equity in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) Facility owned by TransAlta Renewables.

(4) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.

(5) Our interests in these facilities are through our ownership interest in TA Cogen.

Our interest in the Fort Saskatchewan facility is held through TA Cogen. See " *Business of TransAlta – Non-Controlling Interests* " in this AIF. The 118 MW natural gas-fired Combined-Cycle cogeneration Fort Saskatchewan plant is owned by TA Cogen and Strongwater Energy Ltd. The facility provides electricity and steam to Dow Chemical Canada Inc. under the terms of a long-term contract which expires in 2019.

Our Poplar Creek plant is located in Fort McMurray, Alberta. On August 31, 2015, the Corporation restructured its contractual arrangement for the power generation services of its Poplar Creek plant. The Poplar Creek co-generation facility had been built and contracted to provide steam and electricity to Suncor's oil sands operations. Under the terms of the new arrangement, Suncor acquired from the Corporation two steam turbines with an installed capacity of 126 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the co-generation facility and has the right to use the full 230 MW capacity of the Corporation's gas generators until December 31, 2030. Ownership of the entire Poplar Creek co-generation facility will transfer to Suncor in 2030.

The Mississauga Facility is owned by TA Cogen. See " *Business of TransAlta – Non-Controlling Interests* " in this AIF. It is a Combined-Cycle cogeneration facility designed to produce 108 MW of electrical energy. The capacity was contracted under a long-term contract with the OEFC which was terminated effective December 31, 2016. The Mississauga Facility entered into an enhanced dispatch contract with the IESO effective January 1, 2017 for a 2 year term. Prior to July 2005, the Mississauga Facility also provided cogeneration services to Boeing Canada Inc. ("Boeing"). Boeing exercised its right under the cogeneration services agreement to no longer take and pay for cogeneration services due to the closure of its manufacturing facility. Boeing remains entitled to any steam credits which are based on the total plant electricity generation revenue or market based lease rates if the site discontinues electricity generation. On or prior to each of January 1, 2018 and 2023, Boeing must give notice of its intention to continue or discontinue cogeneration services. In addition, on those same dates, Boeing has the option to require

the removal of the Mississauga plant from the leased lands or purchase the Mississauga plant at its net salvage value.

The Ottawa plant is owned by TA Cogen. See "*Business of TransAlta – Non-Controlling Interests*" in this AIF. It is a Combined-Cycle cogeneration facility designed to produce 74 MW of electrical energy. On August 30, 2013, the Corporation announced the recontracting of the plant with the IESO for a 20-year term, effective January 2014. The Ottawa plant also provides steam, hot water, and chilled water to the member hospitals and treatment centers of the Ottawa Health Sciences Centre and the National Defence Medical Centre. The thermal energy contract with the Ottawa Health Sciences Centre expires January 1, 2024 and the thermal energy contract with the National Defence Medical Centre has an initial term which expires on December 31, 2017; however, pursuant to its terms, it has automatically renewed for two years to December 31, 2019.

The Sarnia plant is a 506 MW Combined-Cycle cogeneration facility that provides steam and electricity to nearby industrial facilities owned by ARLANXEO Canada Inc. (formerly LANXESS AG), Nova Chemicals (Canada) Ltd. ("NOVA") (which in turn supplies Styrolution, a Styrene production facility formerly owned by NOVA) and Suncor Energy Products Inc. In September 2009, we signed a new contract with the IESO, effective as of July 1, 2009 and terminating on December 31, 2025. This agreement includes provisions for the parties to share in the impact and benefit of changes in customer steam load or loss of steam customer. The current steam contracts expire at the end of 2022. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Sarnia cogeneration facility on January 6, 2016, and subsequently on November 30, 2016, the economic interest was replaced with direct ownership of the entity that owns the Sarnia cogeneration plant. See "*Business of TransAlta – Non-Controlling Interests.*"

The Windsor plant is owned by TA Cogen. See "*Business of TransAlta – Non-Controlling Interests*" in this AIF. It is a Combined-Cycle cogeneration facility designed to produce 72 MW of electrical energy, of which, 50 MW was sold under a long-term contract to the OEFC. This agreement with the OEFC expired November 30, 2016. Effective December 1, 2016, the Windsor plant began operating under an agreement with the IESO with a 15 year term for up to 72 MW of capacity. The Windsor plant also provides thermal energy to Chrysler Canada Inc.'s minivan assembly facility in Windsor that expires in 2018.

Australian Gas Business Segment

The following table summarizes our natural gas-fired and diesel fired generation facilities:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Parkeston [3] [6]	WA [7]	50	55	1996	LTC	2026
Solomon [3]	WA [7]	100	125	2014	LTC	2028
South Hedland [3] [5]	WA [7]	100	150	2017	LTC	2042
Southern Cross Energy [3] [4]	WA [7]	100	245	1996	LTC	2023
Total Aus Gas Net Capacity			**575**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As of the date of this Annual Information Form, TransAlta owns approximately 64 per cent of the voting equity in TransAlta Renewables.
(2) Where no contract expiry date is indicated, the facility operates as merchant.
(3) TransAlta Renewables owns an economic interest in the facility.
(4) Comprised of four facilities.
(5) Plant is under construction and expected to be fully commissioned in mid-2017.
(6) Plant contracted to October 2026 with early termination options beginning in 2021.
(7) Western Australia.

The Parkeston plant is a 110 MW dual-fuel natural gas and diesel fired power station, which we own in partnership through a 50/50 joint venture with NP Kalgoorlie Pty Ltd., a subsidiary of Newmont Australia Limited. The Parkeston facility primarily supplies energy to Kalgoorlie Consolidated Gold Mines and the initial supply contract ended in 2016. The plant has been re-contracted effective November 1, 2016, and the agreement extends the previous contract to October 2026, with options for early termination available to either party beginning in 2021. Any merchant capacity and energy are sold into Western Australia's wholesale electricity market. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Parkeston facility on May 7, 2015. See "*General Developments of the Business – Corporate and Energy Marketing*" in this AIF.

We acquired the 125 MW natural gas and diesel fired Solomon power station in September 2012 from Fortescue. The Solomon facility is fully contracted with Fortescue under a long-term contract that is intended to support their iron ore mining operations. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Solomon facility on May 7, 2015. See "*General Developments of the Business – Corporate and Energy Marketing*" in this AIF.

Southern Cross Energy is composed of four natural gas and diesel-fired generation facilities with a combined capacity of 245 MW. Southern Cross Energy sells its output pursuant to a contract with BHP Billiton Nickel West which was renewed in October of 2013 for ten years. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the Southern Cross Energy facilities on May 7, 2015. See "*General Developments of the Business – Corporate and Energy Marketing*" in this AIF.

In 2014, we established the Fortescue River Gas Pipeline joint venture with DBP Development Group. The joint venture (of which TransAlta is a 43% partner) was successfully awarded the contract to design, build, own and operate the 270 km Fortescue River Gas Pipeline to deliver natural gas to TransAlta's Solomon Power Station. The pipeline was completed in the first quarter of 2015 and operates under a take-or-pay gas transport agreement with a Fortescue Metals Group subsidiary for an initial term of 20 years. The 16-inch diameter pipeline has an initial free-flow capacity of 64 TJ per day. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the pipeline on May 7, 2015. See "*General Developments of the Business – Corporate and Energy Marketing*" in this AIF.

In 2014, TransAlta was selected as the successful bidder to design, build, own and operate a 150 MW combined cycle power station near South Hedland, Western Australia. Construction began in early 2015 and the plant is expected to be fully commissioned in 2017. On December 8, 2016, the OCGT was commissioned and hand-over occurred. A commercial agreement was executed with Horizon Power to supply electricity generated from the OCGT in the interim. The plant is being constructed under an engineering, procurement and construction agreement with IHI Engineering Australia, a wholly owned subsidiary of IHI Corporation. The plant is fully contracted with

two customers for a 25-year term. The majority of the plant's capacity is contracted to Horizon Power, the state owned electricity supplier in the region. The second customer is the port operations of Fortescue Metals Group. TransAlta Renewables acquired an economic interest based, in part, on the cash flows of the South Hedland facility on May 7, 2015. See "*General Developments of the Business – Corporate and Energy Marketing*" in this AIF.

All of our Australian assets are owned, directly or indirectly, by TransAlta Energy (Australia) Pty Ltd. ("TEA"). On May 7, 2015, TransAlta Renewables acquired from the Corporation tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows of TEA, in consideration for a payment equal to $1.78 billion, which amount includes the cost of funding the remaining construction costs for South Hedland.

Hydro Business Segment

The Hydro business segment holds an interest in 948 gross MWs. The facilities are located in British Columbia, Alberta, Ontario, and Washington State.

As well as contracting for power, long-term and short-term contracts are entered into to sell the environmental attributes from the merchant hydro facilities. These activities help to ensure earnings consistency from these assets. Generally, for facilities under long-term contract, the benefit of the environmental attributes generated flow through to the contract holder.

The following table summarizes our hydroelectric facilities:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Barrier	AB	100	13	1947	Alberta PPA	2020
Bearspaw	AB	100	17	1954	Alberta PPA	2020
Cascade	AB	100	36	1942, 1957	Alberta PPA	2020
Ghost	AB	100	54	1929, 1954	Alberta PPA	2020
Horseshoe	AB	100	14	1911	Alberta PPA	2020
Interlakes	AB	100	5	1955	Alberta PPA	2020
Kananaskis	AB	100	19	1913, 1951	Alberta PPA	2020
Pocaterra	AB	100	15	1955	Merchant	-
Rundle	AB	100	50	1951, 1960	Alberta PPA	2020
Spray	AB	100	112	1951, 1960	Alberta PPA	2020
Three Sisters	AB	100	3	1951	Alberta PPA	2020
Belly River [3] [4]	AB	100	3	1991	Merchant	-
St. Mary [3] [4]	AB	100	2	1992	Merchant	-
Taylor [3] [4]	AB	100	13	2000	Merchant	-
Waterton [3] [4]	AB	100	3	1992	Merchant	-
Bighorn	AB	100	120	1972	Alberta PPA	2020
Brazeau	AB	100	355	1965, 1967	Alberta PPA	2020
Akolkolex [3] [4]	BC	100	10	1995	LTC	2046
Pingston [3] [4]	BC	50	23	2003, 2004	LTC	2023
Bone Creek [3] [4]	BC	100	19	2011	LTC	2031
Upper Mamquam [3] [4]	BC	100	25	2005	LTC	2025
Appleton [3] [4]	ON	100	1	1994	LTC	2030
Galetta [3] [6]	ON	100	2	1998	LTC	2030
Misema [3]	ON	100	3	2003	LTC	2027
Moose Rapids [3]	ON	100	1	1997	LTC	2030
Ragged Chute [3] [4]	ON	100	7	1991	LTC	2029
Skookumchuck [5]	WA	100	1	1970	LTC	2020
Total Hydroelectric Net Capacity			**926**			

Notes:

(1) MW are rounded to the nearest whole number. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As of the date of this Annual Information Form, TransAlta owns approximately 64 per cent of the voting equity in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) Facility owned by TransAlta Renewables.

(4) These facilities are EcoLogo® certified ("EcoLogo"). EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards.

(5) This facility is used to provide a reliable water supply to Centralia Coal.

(6) Galetta was originally built in 1907, but was retrofitted in 1998.

Bow River System

Barrier is a run-of-river hydroelectric facility with installed capacity of 13 MW located on the Kananaskis River in Seebe, Alberta. It has been operating since 1947. The facility operates under an Alberta PPA.

Bearspaw is a hydroelectric facility with installed capacity of 17 MW located on the Bow River in Calgary, Alberta. It has been operating since 1954. The facility operates under an Alberta PPA.

Cascade is a hydroelectric facility with installed capacity of 36 MW located on the Cascade River in Banff National Park, Alberta. We purchased this facility from the Government of Canada in 1941. The following year, we built a new dam and power plant to replace the original, and then, in 1957, added a second generating unit. The facility operates under an Alberta PPA.

Ghost is a hydroelectric facility with installed capacity of 54 MW located on the Bow River in Cochrane, Alberta. It has been operating since 1929. The facility operates under an Alberta PPA.

Horseshoe is a run-of-river hydroelectric facility with installed capacity of 14 MW located on the Bow River in Seebe, Alberta. It has been operating since 1911. The facility operates under an Alberta PPA.

Interlakes is a hydroelectric facility with installed capacity of 5 MW located at Kananaskis Lakes, Alberta. It has been operating since 1955. The facility operates under an Alberta PPA.

Kananaskis is a run-of-river hydroelectric facility with installed capacity of 19 MW located on the Bow River in Seebe, Alberta. It has been operating since 1913. It was expanded in 1951 and modified in 1994. The facility operates under an Alberta PPA.

Pocaterra is a hydroelectric facility with installed capacity of 15 MW located at Kananaskis Lakes, Alberta. It has been operating since 1955. Generation from the facility is sold in the Alberta spot market.

Rundle is a hydroelectric facility with installed capacity of 50 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. It has been operating since 1951. The facility operates under an Alberta PPA.

Spray is a hydroelectric facility with installed capacity of 112 MW located in Canmore, Alberta on the Spray system. The plant uses water from the Spray Lakes Storage Reservoir. It has been operating since 1951. The facility operates under an Alberta PPA.

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

Oldman River System

The Belly River facility is owned by TransAlta Renewables. Belly River is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Waterton-St. Mary Headworks Irrigation Canal System, east of the Waterton Reservoir, approximately 75 kilometres southwest of Lethbridge in Southern Alberta. Due to its location along the irrigation canal, Belly River operates from April to October when water is diverted through the canal as part of the St. Mary Irrigation District Water Management Plan. It has been operating since 1991. We acquire the generation from the facility pursuant to a Renewables PPA (as defined below), and subsequently sell such generation in the Alberta spot market.

The St. Mary facility is owned by TransAlta Renewables. St. Mary is a run-of-river hydroelectric facility with installed capacity of 2 MW located at the base of the St. Mary Dam on the Waterton Reservoir, near Magrath, in Southern Alberta. It has been operating since 1992. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Taylor facility is owned by TransAlta Renewables. Taylor is a run-of-river hydroelectric facility with installed capacity of 13 MW and is located adjacent to the Taylor Coulee Chute on the Waterton-St. Mary Headworks Irrigation Canal System, which is owned by the Government of Alberta. It has been operating since 2000. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Waterton facility is owned by TransAlta Renewables. Waterton is a run-of-river hydroelectric facility with installed capacity of 3 MW located at the base of the Waterton Dam on the Waterton Reservoir, near Hillspring, southwest of Lethbridge, Alberta. It has been operating since 1992. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

North Saskatchewan River System

Bighorn is a hydroelectric facility with installed capacity of 120 MW located in Nordegg, Alberta. It has been operating since 1972. The facility operates under an Alberta PPA.

Brazeau is a hydroelectric facility with installed capacity of 355 MW located in Drayton Valley, Alberta. It has been operating since 1965. The facility operates under an Alberta PPA.

Akolkolex River System

The Akolkolex facility is owned by TransAlta Renewables. Akolkolex is a run-of-river hydroelectric facility with installed capacity of 10 MW located on the Akolkolex River, south of Revelstoke, British Columbia. It has been operating since 1995. In 2016, TransAlta entered into a new 30 year agreement to sell the output from the facility to British Columbia Hydro Power Authority (“BC Hydro”).

Pingston is a run-of-river hydroelectric facility with installed capacity of 45 MW located on Pingston Creek, southwest of Revelstoke, British Columbia and down river of the Akolkolex facility. It has been operating since 2003. TransAlta Renewables owns the facility equally with Brookfield Renewable Power Inc. The output from the facility is sold to BC Hydro.

Thompson River System

The Bone Creek facility is owned by TransAlta Renewables. Bone Creek is a run-of-river hydroelectric facility with installed capacity of 19 MW located on Bone Creek, 90 kilometres south of the town of Valemount, British Columbia. It has been operating since 2011. The output from the facility is under contract with BC Hydro. The facility also currently qualifies for payments of $10/MWh until 2020 from Natural Resources Canada ("NRCan"), a division of the federal government, through the ecoEnergy for Renewable Power ("eERP") program.

Mamquam River System

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

Mississippi River System

The Appleton facility is owned by TransAlta Renewables. Appleton is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Mississippi River, near Almonte, Ontario. The facility has been operating since 1994. Generation from this facility is sold to the IESO under a contract that terminates December 31, 2030.

The Galetta facility is owned by TransAlta Renewables. Galetta is a run-of-river hydroelectric facility with installed capacity of 2 MW located on the Mississippi River, near Galetta, Ontario. This facility was originally built in 1907 and retrofitted in 1998. Generation from this facility is sold to the IESO under a contract that terminates December 31, 2030.

Misema River System

The Misema facility is owned by TransAlta Renewables. Misema is a run-of-river hydroelectric facility with installed capacity of 3 MW located on the Misema River, close to Englehart, in northern Ontario. This facility has been operating since 2003. Generation from this facility is sold to the IESO under a contract that terminates May 3, 2027.

Wanapitei River System

The Moose Rapids facility is owned by TransAlta Renewables. Moose Rapids is a run-of-river hydroelectric facility with installed capacity of 1 MW located on the Wanapitei River, near Sudbury, in northern Ontario. This facility has been operating since 1997. Generation from this facility is sold to the IESO under a contract that terminates December 31, 2030.

Montréal River System

Ragged Chute is a run-of-river hydroelectric facility with installed capacity of 7 MW located on the Montréal River, south of New Liskeard, in northern Ontario. We lease this facility from Ontario Power Generation Inc. and it has been operating since 1991. Generation from this facility is sold to the IESO under a contract that terminates June 30, 2029. On January 6, 2016 TransAlta Renewables acquired from the Corporation tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows, in part, from the Ragged Chute Facility; and subsequently on November 30, 2016, the economic interest was replaced with direct ownership of the entity that owns the Ragged Chute hydro facility. See "*Business of TransAlta – Non-Controlling Interests*" in this AIF.

Centralia

We own a 1 MW hydroelectric generating facility on the Skookumchuck River near Centralia, and related assets which are used to provide water supply to our generation facilities in Centralia. On December 10, 2010, we entered into an agreement with Puget Sound Energy ("PSE") for Skookumchuck to provide power until 2020.

Wind and Solar Business Segment

As at December 31, 2016, the Wind and Solar segment held interests in approximately 1,505 MW of gross wind generating capacity from 11 wind farms in Western Canada, four in Ontario, two in Québec, two in New Brunswick, and two in the United States, more specifically in the states of Wyoming and Minnesota. We also own a 21 MW solar facility in the state of Massachusetts in the United States.

Wind and solar are not generally a dispatchable fuel; therefore, in merchant markets, wind and solar assets may not be able to secure the annual average pool price. As such, we make different assumptions in forecast revenue received for generation from a wind or solar asset compared to a base load asset. If these price assumptions and generation production forecasts are not correct, the corresponding revenue received may be reduced. Generation production forecasts are based on the long-term average production forecast for a site, reflecting historical climatic conditions. Within any year there may be variations from this long-term average. In order to forecast generation production, a number of factors have to be assumed based on historic on-site data. For a wind farm, this includes wind farm design including wake and array losses, wind shear and the electrical losses within the site. For a solar plant, long-term energy production depends on panel angle and row spacing, amount of sun, ambient conditions such as temperature and wind speed and losses at the site. If these assumptions are incorrect then actual production will be higher or lower than the long-term forecast for the site.

As well as contracting for power, we also enter into long-term and short-term contracts to sell the environmental attributes from the merchant wind facilities including offsets and renewable energy credits. These activities help to ensure earnings consistency from these assets. Generally, for facilities under long-term contract, the purchaser under such long-term contracts also has the benefit of any environmental

attributes.

The following table summarizes our Wind and Solar generation facilities:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)[1]	Commercial Operation Date	Revenue Source	Contract Expiry Date[2]
Ardenville [4] [5]	AB	100	69	2010	Merchant	-
Blue Trail [4] [5]	AB	100	66	2009	Merchant	-
Castle River [4] [5] [6]	AB	100	44	1997-2001	Merchant	-
Cowley North [4] [5]	AB	100	20	2001	Merchant	-
Macleod Flats [4]	AB	100	3	2004	Merchant	-
McBride Lake [4] [5]	AB	50	38	2004	LTC	2024
Sinnott [4] [5]	AB	100	7	2001	Merchant	-
Soderglen [4] [5]	AB	50	35	2006	Merchant	-
Summerview 1 [4] [5]	AB	100	70	2004	Merchant	-
Summerview 2 [4] [5]	AB	100	66	2010	Merchant	-
Wintering Hills [9]	AB	51	45	2012	Merchant	-
Mass Solar [8]	MA	100	21	2012-2015	LTC	2032-2045
Lakeswind	MN	100	50	2014	LTC	2034
Kent Hills [4] [5]	NB	83	80	2008	LTC	2033
Kent Hills Expn. [4] [5]	NB	83	45	2010	LTC	2035
Kent Breeze	ON	100	20	2011	LTC	2031
Melancthon I [4] [5]	ON	100	68	2006	LTC	2026
Melancthon II [4] [5]	ON	100	132	2008	LTC	2028
Wolfe Island [4] [5]	ON	100	198	2009	LTC	2029
Le Nordais [4] [5] [7]	QC	100	98	1999	LTC	2033
New Richmond [4] [5]	QC	100	68	2013	LTC	2033
Wyoming Wind [3]	WY	100	144	2003	LTC	2028
Total Wind and Solar Net Capacity			**1,384**			

Notes:

(1) MW are rounded to the nearest whole number. Column may not add due to rounding. Net Capacity Ownership Interest includes 100 per cent of the generating capacity owned by TransAlta Renewables. As of the date of this Annual Information Form, TransAlta owns approximately 64 per cent of the voting equity in TransAlta Renewables.

(2) Where no contract expiry date is indicated, the facility operates as merchant.

(3) TransAlta Renewables owns an economic interest in the facility.

(4) Facility owned by TransAlta Renewables.

(5) These facilities are EcoLogo® certified. EcoLogo certification is granted to products with environmental performance that meet or exceed all government, industrial safety and performance standards.

(6) Includes seven additional turbines at other locations.

(7) Comprised of two facilities.

(8) Comprised of multiple facilities.

(9) On January 16, 2017, we announced the sale of our 51% interest in Wintering Hills. The transaction closed on March 1, 2017. See "*General Developments of the Business – Recent Developments*" in this AIF.

The Ardenville facility is owned by TransAlta Renewables. Ardenville is a 69 MW wind farm located approximately eight kilometres south of Fort Macleod, Alberta adjacent to the Macleod Flats wind facility. We constructed the project, which commenced commercial operations on November 10, 2010. The Ardenville wind farm is entitled to receive payments of $10/MWh until 2020 from NRCan, through the eERP program. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Blue Trail facility is owned by TransAlta Renewables. Blue Trail is a 66 MW wind farm located in southern Alberta which commenced commercial operations in November 2009. The Blue Trail wind farm is entitled to receive payments of $10/MWh until 2019 from NRCan, through the eERP program. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Castle River facility is owned by TransAlta Renewables. Castle River is a 40 MW wind farm located in Pincher Creek, Alberta. We also own and operate seven additional turbines totalling 4 MW located individually in the Cardston County and Hillspring areas of southwestern Alberta. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Cowley North facility is owned by TransAlta Renewables. Cowley North is a 20 MW wind farm, located in Pincher Creek, Alberta. It commenced commercial operations in the fall of 2001. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Macleod Flats facility is owned by TransAlta Renewables. Macleod Flats consists of a single 3 MW turbine and is located near Fort Macleod. It was commissioned in 2004 and was purchased by us in 2009. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The McBride Lake facility is owned by TransAlta Renewables. McBride Lake is a 75 MW wind farm located at Fort Macleod, Alberta. We constructed the wind farm, which commenced commercial operations in 2004. McBride Lake is operated by us. TransAlta Renewables owns the

facility equally with ENMAX Green Power Inc. The output from the facility is 100 per cent contracted in the form of a 20-year PPA with ENMAX Energy Corporation. We also own an interest in the 0.7 MW McBride Lake East facility in the same vicinity through our ownership interest in TransAlta Renewables.

The Sinnott facility is owned by TransAlta Renewables. Sinnott has a total installed capacity of 7 MW and is located in Pincher Creek, Alberta. It commenced commercial operations in the fall of 2001. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Soderglen facility is owned by TransAlta Renewables. Soderglen is a 71 MW facility located in southern Alberta, southwest of Fort Macleod and 40 kilometres from our wind operations near Pincher Creek. The facility began commercial operations in September 2006. TransAlta Renewables owns the facility equally with Nexen Energy ULC. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell 50 per cent of such generation in the Alberta spot market (which excludes that portion of generation that is owned by Nexen Energy ULC).

The Summerview 1 facility is owned by TransAlta Renewables. Summerview 1 is a 68 MW wind farm located approximately 15 kilometres northeast of Pincher Creek, Alberta. We constructed Summerview and it commenced commercial operations in 2004. The Summerview 1 facility, together with an existing 1.8 MW turbine in the area, brings the total wind generation capacity at that location to 70 MW. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

The Summerview 2 facility is owned by TransAlta Renewables. Summerview 2 is a 66 MW wind farm located northeast of Pincher Creek, Alberta. We constructed the facility, which began commercial operations in February 2010. The Summerview 2 wind farm expansion is entitled to receive payments of $10/MWh until 2020 from NRCan, through the eERP program. We acquire the generation from the facility pursuant to a Renewables PPA, and subsequently sell such generation in the Alberta spot market.

Wintering Hills is an 88 MW wind farm located in southern Alberta, north of Hussar, Alberta. The facility began commercial operations in June 2012. On December 31, 2016, TransAlta owned a 51 per cent interest in this facility and Teck Resources Limited held the remaining 49 per cent interest. On January 16, 2017, we announced the sale of our 51% interest in Wintering Hills. The transaction closed on March 1, 2017. See "*General Developments of the Business – Recent Developments*" in this AIF.

The Mass Solar Farm is a 21 MW solar project consisting of multiple facilities located in Massachusetts. The wind farm was acquired in 2015 from an affiliate of Rockland Capital LLC. The operational solar farm is contracted under a long-term PPA with several high quality counterparties. See "*General Developments of the Business – Generation and Business Development.*"

The Lakeswind Wind Farm is a 50 MW wind project located near Rollag, Minnesota. The wind farm was acquired in 2015 from an affiliate of Rockland Capital LLC. The wind farm is fully operational and contracted under a long-term PPA until 2034 with several high quality counterparties. See "*General Developments of the Business – Generation and Business Development*" in this AIF.

The Kent Hills facility is owned by TransAlta Renewables. Kent Hills is a 96 MW project located in Kent Hills, New Brunswick, and delivers power under a 25 year LTC with New Brunswick Power. Natural Forces

Technologies Inc. ("Natural Forces"), an Atlantic Canada-based wind developer, is our co-development partner in this project and exercised its option to purchase 17 per cent of the Kent Hills project in May 2009. Kent Hills commenced commercial operations in 2008. Kent Hills is entitled to receive eERP payments until 2018.

The Kent Hills expansion is owned by TransAlta Renewables. The Kent Hills expansion is a 54 MW wind farm which also delivers power under a 25 year LTC with New Brunswick Power. Natural Forces exercised their option to purchase a 17 per cent interest in the Kent Hills expansion project subsequent to the commencement of commercial operations. The facility commenced commercial operations in 2010. The Kent Hills expansion is entitled to receive eERP payments until 2020.

Kent Breeze is a 20 MW wind project located in Thamesville, Ontario. This facility commenced commercial operations in 2011. Generation from this facility is sold to the IESO. Kent Breeze is entitled to receive eERP payments until 2021.

The Melanchton I facility is owned by TransAlta Renewables. Melancthon I is a 68 MW wind project located in Melancthon Township near Shelburne, Ontario. It commenced commercial operations in 2006. Generation from this facility is sold to the IESO.

The Melancthon II facility is owned by TransAlta Renewables. Melancthon II is a 132 MW wind project located adjacent to Melancthon I, in Melancthon and Amaranth Townships. It commenced commercial operations in 2008. Generation from this facility is sold to the IESO. Melancthon II is entitled to receive eERP payments until 2018.

The Wolfe Island facility is owned by TransAlta Renewables. Wolfe Island is a 198 MW wind project located on Wolfe Island, near Kingston, Ontario. This facility commenced commercial operations in 2009. Generation from this facility is sold to the IESO. Wolfe Island is entitled to receive eERP payments until 2019.

Le Nordais is located at two sites on the Gaspé Peninsula of Québec: Cap-Chat and Matane with a combined 98 MW of installed capacity. It commenced commercial operations in 1999. Generation from this facility is sold to Hydro-Québec. On January 6, 2016, TransAlta Renewables acquired from the Corporation tracking preferred shares that entitle TransAlta Renewables to an economic interest based on the cash flows, in part, from the Le Nordais facilities; and subsequently on November 30, 2016, the economic interest was replaced with direct ownership of the entity that owns the Le Nordais wind farm. See "*Business of TransAlta – Non-Controlling Interests*" in this AIF.

The New Richmond facility is owned by TransAlta Renewables. New Richmond is a 68 MW wind project also located on the Gaspé Peninsula. New Richmond is contracted under a 20-year Electricity Supply Agreement with Hydro-Québec Distribution. It commenced commercial

operations in 2013.

The Wyoming Wind Farm is a 144 MW wind project located near Evanston, Wyoming. The wind farm was acquired in December 2013 from an affiliate of NextEra Energy Resources, LLC. The wind farm is contracted under a long-term PPA until 2028 with an investment grade counterparty. Concurrent with closing, TransAlta Renewables acquired tracking preferred shares from the Corporation that provides TransAlta Renewables with an economic interest in the wind farm.

All of the electricity generated and sold by our Wind segment within Canada, with the exception of Macleod Flats, Kent Breeze, and Wintering Hills, are from facilities that are EcoLogo certified. We are an EcoLogo certified distributor of Alternative Source Electricity through Environment Canada's Environmental Choice program.

U.S. Coal Business Segment

Our U.S. Coal facilities are summarized in the following table:

Facility Name	Province/ State	Ownership (%)	Net Capacity Ownership Interest (MW)	Commercial Operation Date	Revenue Source	Contract Expiry Date
Centralia Thermal No. 1	WA	100	670	1971	LTC/Merchant	2020
Centralia Thermal No. 2	WA	100	670	1971	LTC/Merchant	2025
Total U.S. Coal Net Capacity			**1,340**			

We own a two-unit 1,340 MW thermal facility in Centralia, Washington, located south of Seattle. We have entered into a number of multiple year medium and short-term energy sales agreements from the Centralia Thermal plant. In 2011, Washington State passed the TransAlta Energy Bill (chapter 180, Laws of 2011) (the "Bill'') allowing the Centralia Thermal plant to comply with the State's GHG emissions performance standards by shutting down one of its two boilers by the end of 2020 and the other by the end of 2025. The Bill removed restrictions that had previously been imposed on the facility limiting the duration of new contracts from the facility, and limiting the technology that the facility would be required to implement for nitrogen oxides ("NOx") controls. On July 25, 2012, we announced that we entered into an 11-year agreement to provide electricity from our Centralia Thermal plant to PSE. The contract began in 2014 and runs until 2025 when the plant is scheduled to be shut down. Under the agreement, PSE bought 180 MW of firm, base-load power starting in December 2014. In December 2015, the contract increased to 280 MW and from December 2016 to December 2024 the contract is for 380 MW. In the last year of the contract, the contracted volume is for 300 MW.

On July 30, 2015, the Corporation announced that it was moving ahead with plans to invest U.S.$55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The initiative is part of Centralia's transition from coal-fired operations in Washington, beginning on December 31, 2020. The U.S.$55 million community investment is part of the Bill passed in 2011. This bill was an agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State, closing the Centralia facility's two units, one in 2020 and the other in 2025. Approved funding for community investment included approximately U.S.$1.1 million incurred as at December 31, 2016.

We sell electricity from the Centralia Thermal plant into the Western Electricity Coordinating Council ("WECC") and, in particular, on the spot market in the U.S. Pacific Northwest energy market. Our strategy is to balance contracted and non-contracted sales of electricity to manage production and price risk.

We also own a coal mine adjacent to the Centralia facility; however, we stopped mining operations at our Centralia coal mine on November 27, 2006. Although we estimate that certain coal reserves remain to be extracted, we have not yet received permits for, nor developed the new area from which this coal could be produced. Coal to fuel the Centralia plant is sourced from the Powder River Basin in Montana and Wyoming. TransAlta is currently party to coal contracts with three suppliers which expire between 2017 and 2025. We expect to continue to source our future coal needs from the Powder River Basin. In December 2014, we began fine coal recovery operations at our Centralia mine. This operation recovers previously wasted coal as part of the mine reclamation process and is expected to provide roughly ten per cent of the fuel use by the Centralia plant.

Under the U.S. Federal Mine Safety and Health Act, TransAlta must report all "significant and substantial" citations at its Centralia mine. During 2016, TransAlta had no reportable events relating to electric equipment and the examination, testing and maintenance thereof. The mine is not in operation. There were no injury incidents or fatalities at the mine during 2016. The total dollar value of all Mine Safety and Health Administration ("MSHA") assessments was not significant. There are no pending legal actions before the Federal Mine Safety and Health Review Commission involving the Centralia mine and none were pending during 2016.

Reportable Events – Centralia Mine

Mine or Operating Name/MSHA Identification Number	Total Number of Section 104 Violations for which Citations Received (#)	Total Number of Orders Issued Under Section 104(b) (#)	Total Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards Under Section 104(d) (#)	Total Number of Flagrant Violations Under Section 110(b)(2) (#)	Total Number of Imminent Danger Orders Issued Under Section 107(a) (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining Related Fatalities (#)	Received Notice of Pattern Violations Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Initiated or Pending During Period (#)
4500416	7	0	0	0	0	$798	0	no	no	0

Energy Marketing Segment

Our Energy Marketing segment provides a number of strategic functions, including the following:

- gathering and analyzing market trends to enable more effective strategic planning and decision making;
- negotiating and entering into contractual agreements with customers for the sale of output from our generation assets, including electricity, steam or other energy-related commodities;
- negotiating and managing fuel supply arrangements with third parties for our generation assets. This includes scheduling, billing and settlement of physical deliveries of natural gas and other fuels;
- the development and execution of our corporate hedging strategy within Board approved parameters; and
- the optimization of the asset fleet to maximize gross margin and mitigation of market risks.

The Energy Marketing segment also derives additional revenue by providing fee based asset management services to third parties, by earning margins on third party gas and power transactions, and by trading electricity and other energy commodities (i.e. fuels). The origination and trading activities are focused on the existing asset and customer footprint of the Corporation.

The segment seeks to measure and manage a number of risks for the assets and for our trading books. The key risk control activities of the Energy Marketing segment include the measurement and management of market, credit, operational, reputational, compliance, and legal risks.

The segment uses Value at Risk ("VaR"), Gross Margin at Risk ("GMaR"), and tail risk measures to monitor and manage the risks within our asset and trading portfolios. VaR and GMaR measure the potential losses that could occur over a given time period due to changes in market risk factors. Back tests are used to provide further sensitivities to the market risks within the portfolio. Compliance, reputational, and legal risks are managed within our legal and compliance policies, and monitoring tools are used to flag compliance risks. The Energy Marketing segment actively manages the risks within approved limits and our policies.

Corporate Segment

Our Corporate segment includes the Corporation's central financial, legal, administrative and investing functions.

Non-Controlling Interests

Our subsidiaries and operations that have non-controlling interests are as follows:

TA Cogen

We hold a 50.01 per cent limited partnership interest in TA Cogen, which is an Ontario limited partnership. The remaining 49.99 per cent ownership is held by Canadian Power Holdings Inc., a subsidiary of Cheung Kong Infrastructure Holdings Limited.

TA Cogen holds an interest in the 790 MW Sheerness thermal generation facility in Alberta and the 118 MW Fort Saskatchewan natural gas-fired cogeneration facility in Alberta. TA Cogen also holds an interest in three natural gas-fired cogeneration facilities located in Ontario: (i) the 108 MW Mississauga Facility; (ii) the 74 MW Ottawa plant; and (iii) the 68 MW Windsor plant. Descriptions of these facilities, ownership levels and contract expiry dates are provided under the headings "*Canadian Gas Business Segment*" and "*Canadian Coal Business Segment*" in this AIF.

Kent Hills

We hold, through our ownership of TransAlta Renewables, an 83 per cent interest in the 150 MW Kent Hills wind farm located in New Brunswick. Description of the facility is provided under the heading "*Wind and Solar Business Segment*" in this AIF.

TransAlta Renewables

As of December 31, 2016, we hold an approximate 64 per cent interest in TransAlta Renewables, which is a publicly traded entity. We remain committed to maintaining our position as the majority shareholder of TransAlta Renewables with a goal of maintaining our ownership interest between 60 to 80 per cent.

TransAlta Renewables completed its initial public offering in August of 2013. In connection with the offering, we transferred to TransAlta Renewables certain wind and hydro power generation assets.

On December 20, 2013, we sold to TransAlta Renewables an economic interest in a 144 MW wind farm located in the State of Wyoming for payment equal to U.S.$102 million. The Wyoming wind farm is managed by TransAlta under the terms of the Management and Operational Services Agreement and is operated by NextEra Energy.

On May 7, 2015, we sold to TransAlta Renewables an economic interest based on the cash flows of our Australian assets. The portfolio, held by TransAlta Energy (Australia) Pty Ltd, consists of six operating assets with an installed capacity of 425 MW, the 150 MW South Hedland project currently under construction, as well as a 270 km gas pipeline. The combined value of the Australian Transaction was approximately $1.78 billion. At the closing of the Australian Transaction, TransAlta Renewables paid us $216.9 million in cash as well as approximately $1,067 million through the issuance of a combination of common shares and Class B shares in the capital of TransAlta Renewables.

On January 6, 2016, we sold to TransAlta Renewables an economic interest in the Corporation's Sarnia cogeneration plant, Le Nordais wind farm and Ragged Chute hydro facility for a combined value of $540 million. The Canadian Assets consist of approximately 611 MW of contracted power generation assets located in Ontario and Quebec. The Corporation received cash proceeds of $172.5 million, a $215 million convertible unsecured subordinated debenture and approximately $152.5 million in common shares of TransAlta Renewables. In November 2016, the economic interest was converted to direct ownership of the entities that own the Sarnia cogeneration plant, Le Nordais wind farm and Ragged Chute hydro facility.

We provide all management, administrative and operational services required for TransAlta Renewables to operate and administer its assets and to acquire additional assets.

PPAs

Renewables PPAs

In August of 2013, we entered into long-term power purchase agreements with certain subsidiaries of TransAlta Renewables (each a "Merchant Subsidiary") providing for the purchase by TransAlta, for a fixed price, of all of the power produced at certain merchant facilities (the "Renewables PPAs"). The initial price payable in 2013 by TransAlta for output under the Renewables PPAs was $30.00/MWh for wind facilities and $45.00/MWh for hydroelectric facilities, which amounts are adjusted annually for changes in the Canadian consumer price index. The Canadian consumer price index adjusted prices for 2017 are $31.82/MWh for wind facilities and $47.731/MWh for hydroelectric facilities. Under the terms of each Renewables PPA, the Merchant Subsidiary is under no obligation to deliver any specified amount of energy and, in no event, shall any penalties or curtailment payments be payable under the Renewables PPA. The Merchant Subsidiary will assume all operating and generating risk and TransAlta will only be required to purchase power that is actually produced.

Each Renewables PPA has a term of 20 years or end of asset life, where end of asset life is less than 20 years. Each Renewables PPA may be terminated by: (a) the mutual agreement of the parties; (b) the Merchant Subsidiary upon the occurrence of a material default by TransAlta; and (c) TransAlta (i) upon the occurrence of a material default by the Merchant Subsidiary; (ii) upon a change of control of TransAlta Renewables; or (iii) upon a change of control of the Merchant Subsidiary.

Alberta PPAs

All of our Alberta thermal and hydroelectric facilities, other than the Keephills 3, Genesee 3, Belly River, Pocaterra, Waterton, St. Mary and Taylor facilities, and uprated capacity, operate under Alberta PPAs. The Alberta PPAs establish committed capacity and electrical energy generation requirements and availability targets to be achieved by each thermal plant, energy and ancillary services obligations for the hydroelectric plants, and the price at which electricity is to be supplied. We bear the risk or retain the benefit of availability under or above a targeted Availability (except for those arising from events considered to be force majeure, in the case of the PPA thermal plants) and any change in costs (unless due to a change in law) required to maintain and operate the facilities.

Our thermal facilities are operated by us, however, they are cycled or dispatched by the buyers under the Alberta PPA. Under the Alberta PPAs, we are exposed to electricity price risk if Availability declines below contracted levels (other than as a result of outages caused by an event of force majeure). In those circumstances, we must pay a penalty on the difference between target Availability and actual Availability at a price equal to the 30-day rolling average of Alberta's market electricity prices. This rolling average provision attempts to mitigate price spikes that can occur as a result of sudden outages. We attempt to further mitigate this exposure by maintaining contracted and uncontracted capacity in the market, through operation and maintenance practices, and hedging activities.

Our hydroelectric facilities, other than Belly River, Pocaterra, St. Mary, Taylor and Waterton, are aggregated through one Alberta PPA which provides for financial obligations for energy and ancillary services based on hourly targets. We meet these targeted amounts through physical delivery or third party purchases.

Our compensation under the Alberta PPAs is founded on a pricing formula based on the previous cost of service regime that applied under utility regulation. Key elements of the pricing formula are the amount of common equity deemed to form part of the capital structure, the amount of risk premium attributable to deemed common equity and a recovery of certain fixed and variable costs. Common equity is deemed to be 45 per cent of total capital and the return on equity is set annually at a 4.5 per cent premium over the rate of a Government of Canada Bond with maturity of ten years.

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

The expiry dates for our Alberta PPAs range from 2017 to 2020. We are evaluating the economics of running assets post PPA expiry, taking into account published and expected provincial and federal greenhouse gas ("GHG") and other environmental legislation, including the published federal regulations governing GHG emissions from coal-fired plants. Upon the expiry of the Alberta PPAs, and subject to any legislative limitations, which are addressed below, and our ability to procure an extension to operating licenses, if required, we will then be in a position to sell our electricity to the Alberta Power Pool and to third party purchasers through direct sales agreements.

The buyers under the Alberta PPAs are permitted to return their respective PPAs in certain circumstances to the Balancing Pool. In early 2016, the buyers gave notice to the Balancing Pool of the termination of the PPAs for Sundance A, B, and C, Sheerness, and Keephills. The Balancing Pool confirmed the terminations of the PPAs for Sundance A, B, C, and Sheerness in late 2016 but has not confirmed the termination of the Keephills PPA. For those PPAs that are terminated, the Balancing Pool has assumed the role of buyer and continues to make the energy payment and the capacity payment to TransAlta. It is not known if or when the Keephills PPA will be terminated.

In addition, the Balancing Pool may elect to fully terminate any PPA that has been returned to it, with the result that TransAlta would no longer be bound by the PPA. In such circumstances, the Balancing Pool must provide

TransAlta with notice of the termination and a lump-sum payment, related to the closing net book value of the generating unit, in connection with such termination. If the Balancing Pool exercises its ability to terminate, we will, in those circumstances, be entitled to receive a lump-sum payment in connection with such termination.

Competitive Environment

We are the largest generator of electricity in Alberta, measured by capacity. In addition, we own and operate generating assets in British Columbia, Ontario, Québec, New Brunswick, the State of Washington, the State of Wyoming, the State of Minnesota, the State of Massachusetts, and Western Australia.

The power generation industry in North America is highly competitive and includes a large number of power producers. We compete against independent power producers, utilities that produce power for sale in the merchant market, both public and private investors, and financial intermediaries. We compete in Alberta in a deregulated wholesale power market, and in other jurisdictions that range from partially-regulated to fully regulated wholesale power markets. In Alberta, a large portion of our capacity is subject to Alberta PPAs. Please see the section entitled "*Alberta PPAs*" above in this AIF for a description of these contracts. The ability to compete in deregulated or partially regulated markets is often driven by our cost to produce power and our reliability.

We expect electricity demand growth to be relatively restrained in the current economic environment, but in the longer term most markets are expected to show growing demand for electricity. However, an increasing emphasis on efficiency may reduce future growth rates below historical levels. In addition to increased longer term demand, new investment in natural gas and renewable generation is expected to replace expected coal retirements in response to government policy initiatives. Many of the markets in which we participate have established renewable portfolio targets or standards that require new renewable power investments. As most forms of renewable generation also involve intermittent or uncertain levels and timing of production, higher levels of renewable generation may be accompanied by greater capacity requirements. We believe that continued and growing demand for electricity, renewable portfolio standards, and the potential of increasing amounts of renewable generation to require additional capacity, may provide an opportunity to increase our generation capacity.

Alberta

Approximately 60 to 65 per cent of our capacity is located in Alberta and more than 65 per cent of it is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. Alberta PPAs expire at the end of 2017 (Sundance 1 and 2) and the end of 2020 (Keephills 1 and 2, Sundance 3 to 6, Sheerness, and Hydro). Coal generation sold under Alberta PPAs retain some exposure to market prices as we pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of energy and ancillary services in excess of obligations on our Hydro Alberta PPAs ("hydro peaking"). We enter into financial contracts to reduce our exposure to variable power prices for the significant portion of our remaining generation.

Following the decrease in oil prices, Alberta's annual average demand growth decreased by approximately 1.1 per cent in 2016 compared to 2015. Concurrently over 2015 and 2016, approximately 127 MW of gas generation capacity was added to the market. Power pool prices trended to their lowest levels in the last 10 years, dropping to an average of $18/MWh from $33/MWh in 2015. The decline impacted merchant wind and hydro peaking, which are the portions of our portfolio we cannot effectively hedge due to the intermittency of wind generation and resource uncertainty and the notional size of the PPA pertaining to hydro.

Our current share of offer control in the province is approximately 12 per cent. After expiry of the PPAs in 2021, our share of offer control is forecast to increase to approximately 28 per cent depending on load and supply growth in the province.

Alberta's Climate Leadership Plan, may alter Alberta's competitive landscape. Currently, the marginal cost of generating power from coal is generally most competitive over alternate sources, excluding renewables and must-run cogeneration. If implemented as planned, after the carbon pricing and allowance rules enter into effect in 2018, we expect the incremental cost to coal generation could increase significantly and the production from coal plants could be dispatched after highly efficient combined-cycle gas sources, potentially resulting in lower coal production

and reduced margins. Power demand growth could also decrease as a result of energy efficiency initiatives. We expect that the financial impact of the anticipated decrease in our coal production volumes and higher compliance costs could be partially offset by power price increases, as well as higher benefits from allowances generated by our renewable sources. Until 2020, the impact of carbon prices is limited due to the pass-through of compliance costs to buyers under the legislated Alberta PPAs at contracted plants.

We expect that the elimination of current excess system capacity and future growth in Alberta will be primarily driven by the retirement of coal

units over the next 15 years. Alberta's Climate Leadership Plan projects the replacement of two-thirds of coal production through renewable sources and one-third through gas. We believe that our extensive portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro, and gas that provides us a cost advantage over competitors for construction of new builds. In addition, pursuant to our Memorandum of Understanding ("MOU") with the Government of Alberta, we expect to work collaboratively to enable our coal plants to transform to natural gas and to begin to develop our Brazeau Pumped Storage project, one of the leading hydro power projects on the drawing board in Canada.

U.S. Pacific Northwest

Our capacity in the U.S. Pacific Northwest is comprised of our 1,340 MW Centralia coal plant. Half of the plant capacity is set to retire at the end of 2020, and the other half at the end of 2025.

System capacity in the region is primarily comprised of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited, and further constrained by emphasis on energy efficiency. Our Centralia coal plant can effectively compete against gas generation, although depressed gas prices following the expansion of shale gas production in North America has added to the downward pressure on power prices.

Our competitiveness is enhanced by our long-term contract with Puget Sound Energy for up to 380 MW over the remaining life of the facility. The contract and our hedges allow us to satisfy power requirements from the market when prices fall below our marginal costs of production.

We maintain an opportunity to redevelop Centralia as a gas plant after coal capacity retires, with permitting provided by our agreement for coal transition established with the State of Washington in 2011.

Contracted Gas and Renewables

The market for development or acquisition of gas and renewable generation facilities is highly competitive in all markets in which we operate. Our solid record as operator and developer supports our competitive position. We expect, where possible, to reduce our cost of capital and improve our competitive profile by using project financing and leveraging the lower cost of capital with TransAlta Renewables. In the United States, our substantial tax attributes further increase our competitiveness.

While depressed commodity prices have reduced sectoral growth in the oil, gas, and mining industries, the change is also creating opportunities for us as a service provider as some of our potential customers are more carefully evaluating non-core activities and driving for operational efficiencies. In renewables, we are primarily evaluating greenfield opportunities in Western Canada or acquisitions in other markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities. During the fourth quarter of 2016, we entered into a NUG Contract with the IESO for our Mississauga Facility. The NUG Contract takes effect on January 1, 2017, and we have agreed to terminate the prior contract with the OEFC early, which would have otherwise terminated in 2018. See "*General Developments of the Business – Generation and Business Development*. " The NUG Contract provides us with additional financial flexibility to pay down upcoming debt maturities in this AIF.

Some of our older gas plants are now reaching the end of their original contract life. The plants generally have a substantial cost advantage over new builds and we have been able to add value by re-contracting these plants with limited life-extending capital expenditures. We have recently extended the life of our Ottawa, Windsor, and Parkeston plants in this manner.

Australia

The Department of Treasury for Western Australia expects that the gross state product will continue to grow at relatively low rates by historical standards. The Department of Treasury for Western Australia has forecasted Western Australia's annual growth in gross state product to range from 1.0 per cent to 3.25 per cent for the period from 2017 to 2020. Electricity demand growth is expected to be slow in response to much lower industrial investment in the region. The Australian Energy Market Operator ("AEMO") forecasts the 10 year energy consumption growth rates at about 1.8 per cent (2013/14 to 2023/24), with peak demand growth rates being forecast at 2.1%.

Regulatory Framework

Below is a description of the regulatory framework of the markets which are material to the Corporation.

Alberta

Since January 1, 1996, new generating capacity initiatives in Alberta have been undertaken by independent power producers ("IPP") and have been subject to market forces, rather than rate regulation. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the AESO, based upon offers by generators to sell power. The Market Surveillance Administrator for the Province of Alberta is an independent entity responsible for monitoring and investigating the market behaviour of market participants, including the AESO and the Balancing Pool, and enforcing compliance with all applicable legislation, regulations, AESO and AUC rules. The AUC oversees electricity industry matters, including new power plant and transmission facilities, the distribution and sale of electricity and retail natural gas. The AUC is also responsible for approving the AESO's rules and for determining penalties and sanctions on any participant found to have contravened market rules.

On November 22, 2015, the Government of Alberta announced its Climate Leadership Plan. The Climate Leadership Plan established several environmental and energy targets for Alberta. Please refer to the "*Environmental Risk Management - Ongoing and Recently Passed Environmental Legislation*" of this Annual Information Form for more information.

On May 24, 2016, the Government of Alberta passed the *Climate Leadership Implementation Act* which establishes the carbon tax framework for its application to fuels. It is expected that additional regulations will be developed governing the treatment of large industrial emitters. The Climate Leadership Plan will be implemented for the electricity sector on January 1, 2018.

On November 23, 2016, the Government of Alberta announced reforms to the electricity market which is to include a capacity market. The details of the capacity market design elements have yet to be completed. The AESO has been tasked with designing and implementing the capacity market. The process is expected to take three years with the first procurement expected in 2019.

Ontario

Ontario's electricity market is a hybrid market that includes a wholesale spot electricity market, as well as regulated prices for certain electricity consumers and long-term contracts for the purchase of power issued by the IESO. The Ontario Ministry of Energy takes a lead role in defining the electricity mix to be procured by the IESO, which has the mandate to develop a detailed integrated power supply plan, to procure the electricity generation in that plan and to manage contracts for privately owned generation. The IESO is responsible for managing the Ontario wholesale market and for ensuring the reliability of the electric system in Ontario. As of January 2015, the Ontario Power Authority and the IESO merged into a single entity and continue as IESO. The IESO's mandate, which is to increase the amount of clean and renewable energy in Ontario's electric system, remains unchanged. The electricity sector is regulated by the Ontario Energy Board.

On February 25, 2016, Ontario released draft regulations for its GHG cap-and-trade program that were finalized on May 19, 2016. The regulations became effective January 1, 2017, and will apply to all fossil fuels used for electricity generation. The majority of our gas-fired generation in Ontario will not be significantly impacted by virtue of change-in-law provisions within existing power purchase agreements.

Australia

Australia has two separate electricity markets, the National Electricity Market and the Wholesale Electricity Market ("WEM"), as well as two smaller vertically integrated utilities. The WEM, where our Australian assets are located, includes the South West Interconnected System.

On September 30, 2015, the Minister for Energy announced that the Australian Government had decided to transfer several operational and market functions in the WEM to the Australian Energy Market Operator ("AEMO"). Functions previously performed by the Independent Market Operator, including administering the Gas Bulletin Board and developing the annual Gas Statement of Opportunities, have been transferred to AEMO. The residual functions of the Independent Market Operator were to be reallocated to other entities and, thereafter, the Independent Market Operator would be abolished.

On November 23, 2016, Energy Industry (Rule Change Panel) Regulations 2016, Electricity Industry (Wholesale Electricity Market) Amendment Regulations (No.2) 2016 and Gas Services Information Amendment Regulations (No.2) 2016 were published. These provisions enable the establishment of the Rule Change Panel, transfer rule-making functions from the Independent Market Operator to the Rule Change Panel and implement a new function for the Economic Regulation, which is to support the Rule Change Panel through the provision of secretariat services. Compliance and enforcement functions have also been transferred from the Independent Market Operator to the Economic Regulation Authority.

Competitive Strengths

We believe that we are well positioned to achieve our business strategy due to our competitive strengths, which include the following:

Operating strength – Our gas, wind and hydro fleet performance and our cost structure have outperformed industry standards. Our Canadian gas fleet outperformed the average forced outage rate of our competitors for the time period 2013 to 2014. Based on the North American benchmark database of IHS Inc., our wind farms installed between 2006 to 2008 are in-line with other owners, and for wind farms installed between 2009 to 2010, we are performing slightly better than peers based on our $/MW-year cost structure. The majority of our hydro operations have performed better than or in-line with peers based on the 2015 Navigant Consulting benchmark for their respective size and age. We continue to strive to be leading performers in the operation of our facilities. In addition, availability at our operated Alberta coal facilities beat the 2014 Solomon benchmark for comparable plants.

Stable cash flow base – Through the use of Alberta PPAs and long-term contracts, approximately 73 per cent of our capacity is contracted over the next two years. The net revenue received under these contractual arrangements helps to minimize short-term revenue fluctuations due to the variable price of electricity.

Fuel diversity – We have an interest in a diverse mix of fuels used for the generation of electricity, including coal, natural gas, hydro, wind, and solar. We believe that this mix reduces the impact on our performance in the event of external events affecting one fuel source.

Management team – Our management team has substantial industry, international, investment and market experience.

Energy Marketing expertise – We believe that our Energy Marketing segment has enhanced returns from our existing generation base and has allowed us to obtain more favourable pricing for uncommitted electricity, secure fuel supply on a cost-effective basis and fulfill electricity delivery obligations in the event of an outage.

Wind Generation – Through our ownership interest in TransAlta Renewables, we are one of the largest owners and operators of wind generation in Canada. Our management team has developed key relationships with customers, suppliers and policy makers that provide a competitive advantage in the development, operations and marketing of wind generation.

Environment – We are a recognized leader in sustainable development and we have taken early preventative action on a number of environmental fronts in advance of regulation.

ENVIRONMENTAL RISK MANAGEMENT

We are subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning the generation and transmission of electrical and thermal energy and surface mining. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We

work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

Ongoing and Recently Passed Environmental Legislation

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

Canadian Federal Government

In November 2016, the Canadian federal government announced that coal-fired generation would be phased out by 2030, following a similar commitment by the Alberta provincial government in November 2015. These two decisions changed the coal plant closure requirements, which had previously been guided by the federal regulations that became effective on July 1, 2015 which provided for up to 50 years of life for coal units. According to the new shut-down requirements, the Corporation's older coal units (which retire prior to 2030) will be guided by the 50-year life rule, while newer units (which were previously scheduled to retire post-2030) will face the new 2030 shutdown date. In November 2016, the Corporation signed the Off-Coal Agreement with the Government of Alberta that confirmed the 2030 shutdown commitment for the impacted units.

On November 21, 2016, the Canadian federal government announced that the Department of Environment and Climate Change will be developing regulations for gas-fired generation. The announcement confirmed plans to include specific rules for coal-to-gas converted units, including a proposed 15-year life and a separate emissions intensity standard. The Canadian federal government will conduct consultations on the proposed regulation in the first two quarters of 2017. Finalized regulations are currently expected by the end of 2018.

On October 3, 2016, the Canadian federal government announced its intention to implement a national price on GHG emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022, or a comparable reduction in GHGs under a cap-and-trade program. The application of the price would be co-ordinated with provincial jurisdictions. We do not yet know how such a price mechanism will affect our operations.

Alberta

On November 22, 2015, the Government of Alberta announced through the Climate Leadership Plan its intent, among other things, to phase out emissions from coal-fired generation by 2030, replace two-thirds of the retiring coal-fired generation with renewable generation, and impose a new carbon price of $30 per tonne of CO2 emissions based on an industry-wide performance standard. On March 16, 2016, the Government of Alberta announced the appointment of a coal phase-out facilitator (the "Facilitator") to work with coal-fired electricity generators, the AESO, and the Government of Alberta to develop options to phase out emissions from coal-fired generation by 2030. The Facilitator was tasked with presenting options to the Government of Alberta that will strive to maintain the reliability of Alberta's electricity grid, maintain stability of prices for consumers, and avoid unnecessarily stranding capital.

In March 2016, the Government of Alberta began development of its renewable energy procurement process design for the Alberta Electric System Operator to procure a first block of renewable generation projects to be in-service by mid-2019.

On May 24, 2016, the Government of Alberta passed the Climate Leadership Implementation Act which establishes the carbon tax framework for its application to fuels. It is expected that additional regulations will be developed in 2017 governing the treatment of large industrial emitters. The Climate Leadership Plan will be implemented for the electricity sector on January 1, 2018. On September 14, 2016, the Government of Alberta reconfirmed its commitment to achieve 30 per cent renewables in Alberta's electricity energy mix by 2030.

On November 24, 2016, we entered into an agreement with the Government of Alberta on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before December 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. Under the terms of the Off-Coal Agreement, we will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to terms and conditions including the cessation of all coal-fired emissions in 2030. Other conditions include maintaining prescribed spending on investment and investment related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), and maintaining spending on programs and initiatives to support the communities surrounding the plants, and the employees of the Corporation negatively impacted by the phase-out of coal generation and the fulfillment of all obligations to affected employees.

Additionally, we announced that we had reached an understanding with the Government pursuant to a Memorandum of Understanding to collaborate and cooperate in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the Province of Alberta.

Since 2007, we have incurred costs as a result of GHG legislation in Alberta. On June 29, 2015, the Alberta Government announced an increase to the Specified Gas Emitters Regulation as follows:

- on January 1, 2016, an increase in the GHG reduction obligation for large emitters from 12 per cent to 15 per cent of emissions, with the compliance price of the technology fund rising from $15 per tonne to $20 per tonne; and

- on January 1, 2017, a further increase to a 20 per cent reduction requirement and a $30 per tonne compliance price.

Our exposure to increased costs as a result of environmental legislation in Alberta is mitigated to some extent through change-in-law provisions in our PPAs that allow us the opportunity to recover capital and operating compliance costs from our PPA customers. The GHG offsets created by our Alberta wind facilities are expected to increase in value through 2017, as GHG emitters can use them as compliance instruments in place of contributing to the technology fund. As part of the Climate Leadership Plan, the government has stated its intention to establish a new system of obligations and allowances, benchmarked against highly efficient gas generation, beginning in 2018. The initial compliance price would be set at $30 per tonne, escalating annually.

In Alberta there are additional requirements for coal-fired generation units to implement additional air emission controls for oxides of NOx and SO_2 once the units reach the end of their respective PPAs, in most cases in 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance ("CASA"). The release of the federal regulations in 2012 adopted by the Government of Canada and the Government of Alberta, and the accelerated coal-fired generation retirement schedule, creates a potential misalignment between the CASA air pollutant requirements and schedules, and the retirement schedules for the coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulate emissions, something which has been identified as a matter yet to be addressed in the MOU.

The Government of Alberta's Renewable Electricity Program is intended to encourage the development of 5,000 MW of new renewable electricity capacity by 2030. The AESO is currently soliciting interest in the first competitive procurement for 400 MW under the program. Proponents must submit an expression of interest by late March 2017. The process will be followed by a request for qualification in late April 2017, request for proposal in mid-September 2017 and successful proponents announced in December 2017. Eligible projects must be 5 MW or larger and can be hydro, wind, solar, and certain biomass. The successful projects will be awarded a Renewable Electricity Supply Agreements that utilizes an indexed renewable energy credit or contract for difference mechanism that will fix the price to the proponent over 20 years. The contracts are expected to require the facility to be operational by 2019.

The Government of Alberta has tasked the AESO with transitioning Alberta's energy-only market to a capacity market structure. The capacity market will help to ensure that there is sufficient supply adequacy as over 6,000 MW of coal generation retires by 2030. The new market structure is expected to reduce the reliance on scarcity pricing, which drives energy price volatility and the price signal for new investment, and compensate resource owners with monthly capacity payments for making their capacity available in the energy and ancillary services market. The AESO plans to engage stakeholders in determining the design and implementation of the capacity market over 2017 and 2018 and conduct the first auction in 2019 with a contract delivery year targeted for 2021. The AESO has suggested they will need new capacity in 2021.

Ontario

On February 25, 2016, Ontario released draft regulations for its GHG cap-and-trade program that were finalized on May 19, 2016. The regulations became effective January 1, 2017, and will apply to all fossil fuels used for electricity generation. The majority of our gas-fired generation in Ontario will not be significantly impacted by virtue of change-in-law provisions within existing power purchase agreements.

United States

On August 3, 2015, President Obama announced the Clean Power Plan. The plan sets GHG emission standards for new fossil-fuel based power plants and emission limits for individual states. States will have the option of interpreting their limits in mass-based (tonnes) or rate-based (pounds per megawatt hour) terms. The plan is intended to achieve an overall reduction in GHG emissions of 32 per cent from 2005 levels by 2030. It will be implemented in two stages: (i) 2022 to 2029, and (ii) 2030 and beyond. The recent administration change in the executive branch of the United States is expected to result in a de-emphasis of the Clean Power Plan.

In December 2016, Washington State Governor Jay Inslee released a budget tax proposal that included a carbon tax, where our U.S. Coal plant is located. Under the Governor's proposal, Centralia would be exempted from any carbon tax due to the TransAlta Energy Bill agreed to between TransAlta and the Washington State Government in 2011. The Washington Government brought into force in 2016 the Clean Air Rule to limit carbon emissions from in state GHG emitters.

These additional regulations for existing power plants are not expected to significantly affect our U.S. operations. TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State's climate change program. We believe that there will be no additional GHG regulatory

burden on our U.S. Coal segment given these commitments. The related TransAlta Energy Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation.

In December 2011, the EPA issued national standards for mercury emissions from power plants. Existing sources will have up to four years to comply. We have already voluntarily installed mercury capture technology at our Centralia Thermal plant, and began full capture operations in early 2012. We have also installed additional technology to further reduce NOx, consistent with the Bill passed in 2011.

Effective January 2013, direct deliveries of power to the California Independent System Operator are subject to Cap and Trade Regulations established by the California Air Resource Board. We continue to monitor our GHG inventory into California.

In September 2016, Wyoming's Interim Joint Revenue committee voted down, by a significant margin, a suggested increase to taxes on wind generation. The bill would have increased the current wind tax from $1/MWh to $5/MWh. In January, a private member of the House of Representatives resubmitted a similar bill to Wyoming's Revenue Committee. This bill was also defeated by a significant margin at committee.

Australia

On December 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The $2.55 billion ERF is the centrepiece of the Australian government's policy and provides a policy framework to cut emissions by five per cent below 2000 levels by 2020. The first auction was held in April 2015 and contracts for 47 million tonnes of emissions reductions were awarded at an average price of $13.95 per tonne. The ERF's safeguard mechanism, commencing from July 1, 2016, will ensure emissions reductions purchased by the Australian government through the ERF are not displaced by significant increases in emissions elsewhere in the economy. The ERF and its safeguard mechanism provide incentives to reduce emissions across the Australian economy. The Government has also committed to develop a National Energy Productivity Plan with a target to improve Australia's energy productivity by 40 per cent between 2015 and 2030.

On June 23, 2015, the Australian government reformed the Renewable Energy Target scheme, which is expected to double the amount of large-scale renewable energy being delivered compared to current levels and would result in approximately 23.5 per cent of Australia's electricity generation in 2020 being generated from renewable sources. The scheme was initially introduced in 2001 with three objectives: (i) to establish a mandatory renewable energy target to be achieved in 2020; (ii) to provide incentives for large-scale renewable energy generators in the form of one large-scale generation certificate earned for each MWh of generation; and, (iii) to require retailers and wholesale industrial customers to purchase a specified volume of their electricity from large-scale renewable sourced electricity or incur a penalty of AUD$65/MWh on any shortfall. The amendments reduced the annual targets for large-scale renewable sourced electricity down from 41,000 GWh in 2020 to 33,000 GWh in 2020, held constant at this level until 2030. It is estimated that this will require an additional 5,000 to 6,000 MW of new capacity to be installed to add to the slightly more than 4,000 MW already operating.

TransAlta Activities

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but to the communities in which we operate. We expect that increased scrutiny will be placed on environmental emissions and compliance. We, therefore, take a proactive approach to minimizing risks to our results. Our Board provides oversight to our environmental management programs and emission reduction initiatives in order to ensure continued compliance with environmental regulations.

Our environmental management programs encompass the following elements:

Renewable Power

We continue to invest in and build renewable power resources.

On July 27, 2015, we announced the acquisition of 71 MW of long-term contracted renewable generation assets. The assets acquired include 21 MW of solar projects located in Massachusetts and a 50 MW wind facility in Minnesota. The assets are contracted under long-term power purchase agreements ranging from 20 to 30 years with several high quality counterparties.

On August 31, 2015, as part of the Poplar Creek contract restructuring, we acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and a 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta. On March 1, 2017, we sold our 51% interest in Wintering Hills. See "*General Developments of the Business – Recent Developments*" in this AIF.

Our 68 MW New Richmond wind facility was commissioned in March 2013 and in December 2013 TransAlta acquired a 144 MW wind farm in Wyoming. The Wyoming Wind Farm is fully operational and contracted under a long-term PPA until 2028 with an investment grade counterparty. The economic interest in the wind farm was subsequently acquired by TransAlta Renewables from a subsidiary of the Corporation in consideration for a payment equal to the original purchase price of the acquisition.

TransAlta believes that a larger renewable portfolio provides increased flexibility in generation and creates incremental environmental value through renewable energy certificates or through emission offsets. In addition, we have developed policies and procedures in order to comply with regulatory guidance and to lessen any environmental disruption caused by our renewable power resources, which includes monitoring noise and the avian impacts at our wind generation facilities.

Environmental Controls and Efficiency

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Alberta thermal operations in 2010 to meet the Province's 70 per cent reduction objectives and have carried out additional testing to allow for further mercury control if necessary. At our Centralia coal plant we have been achieving 70 per cent mercury capture since 2012 on a voluntary basis. Our Keephills 3 plant began operation in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at Genesee 3. Uprate projects at our Keephills, Sundance and Sheerness plants have improved the energy and emissions efficiency of those units.

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

Policy Participation

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

Following the announcement of Alberta Climate Leadership Plan, TransAlta has negotiated with the Government of Alberta, using a principles based approach, to ensure the Corporation has the certainty and capacity needed to invest in clean power. An important aspect of these negotiations was the Government of Alberta's commitment to treat coal-fired generators fairly and not unnecessarily strand capital. In November 2016, the Government of Alberta and TransAlta entered into a binding Off-Coal Agreement that provides compensation for the stranded value on the Keephills 3, Genesee 3 and Sheerness coal plants that had useful lives beyond 2030.

Additionally, we reached an understanding with the Government of Alberta pursuant to the MOU to collaborate and cooperate in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the Province of Alberta. Specifically, the parties undertook collaboration to, among other things:

- move toward a Capacity Market, commencing 2021, compared to the current Energy-only market. Under a Capacity Market, generators are compensated for their available capacity;
- develop a policy and facilitate the economic conversion of some coal-fired generation to natural gas-fired generation in Alberta, including securing regulatory cooperation from the Federal Government; and
- develop a policy to address the value of carbon reductions in the generation of electricity from existing wind and hydro production.

The MOU does not create any legally binding obligations between the Government of Alberta and the Corporation and does not impose any obligations on, or constrain the discretion and authority of the Government. The details of the capacity market design elements have yet to be completed. TransAlta will be advocating to ensure that the new market design will improve market reliability and provide greater revenue certainty for generators which will drive needed investment in Alberta.

Offsets Portfolio

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

Environmental Regulations

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

RISK FACTORS

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

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

The operation and maintenance of our facilities involves risks that may materially and adversely affect our business.

The operation, maintenance, refurbishment, construction and expansion of power generation facilities involve risks, including breakdown or failure of equipment or processes, fuel interruption and performance below expected levels of output or efficiency. Certain of our generation facilities, particularly in Alberta, were constructed many years ago and may require significant capital expenditures to maintain peak efficiency or to maintain operations. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities prior to occurrence or eliminate all adverse consequences in the event of failure. In addition, weather related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of our facilities and may materially adversely affect us.

We have entered into ongoing maintenance and service agreements with the manufacturers of certain critical equipment. If a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support, we may have to enter into alternative arrangements with other providers if they cannot perform the maintenance themselves. These arrangements could be more expensive to us than our current arrangements and this increased expense could have a material adverse effect on our business. If we are unable to enter into satisfactory alternative arrangements, our inability to access technical expertise or parts could have a material adverse effect on us.

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

We may be subject to the risk that it is necessary to operate a plant at a capacity level beyond that which we have contracted for power in order to provide steam in fulfillment of such a contract. In such circumstances, the costs to produce the steam being sold may exceed the revenues derived therefrom.

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

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

To comply with environmental regulations, we must incur material capital and operating expenditures relating to environmental monitoring, emissions and effluent control equipment and processes; emissions measurement, verification and reporting; emissions fees and other compliance activities or obligations. We expect to continue to have environmental expenditures in the future. Stricter standards, new or greater regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Corporation subject to environmental regulation and the implementation of provincial, state and national GHG emissions, mercury emissions or other air emissions regulation which in themselves may not be aligned and may imposed varying obligations on us in the jurisdictions in which we operate and which could increase the amount of our expenditures. To the extent these expenditures cannot be passed through to our customers under our power purchase agreements, including Alberta PPAs or otherwise, our costs could be material. In addition, compliance with environmental regulation might result in restrictions on some of our operations. If we do not comply with environmental regulation, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on us or curtail our operations and significant expenditures on compliance, new equipment or technology, reporting obligations and research and development.

On November 22, 2015, the Government of Alberta announced the Alberta Climate Leadership Plan. In respect of the power generation sector, the Climate Leadership Plan targets the retirement of coal generation in Alberta by 2030, replacement of two-thirds of the retiring coal-fired generation with renewable generation (to achieve a 30 per cent share of the provincial electrical system by 2030), and establishment of a new system of GHG obligations and allowances benchmarked against highly efficient gas-fired generation beginning in 2018, at the increased price of $30 per tonne. Additionally, the Government of Alberta has announced the intention to transition the energy-only market to a capacity market. We are carefully reviewing the climate change policy announced by the Government of Alberta to assess how it will impact our business and strategy moving forward. Given this uncertainty in policy, it could have a material adverse effect upon our consolidated financial results.

In addition to environmental regulation, we could also face civil liability in the event that private parties seek to impose liability on us for property damage, personal injury or other costs and losses. We cannot guarantee that

lawsuits or administrative or investigative actions will not be commenced against us and otherwise affect our operations and assets. If an action is filed against us or which may otherwise affect our operations and assets, we could be required to make substantial expenditures to defend or evidence our activities or to bring our Corporation, our operations and assets into compliance, which could have a material adverse effect on our business.

A number of recent federal, provincial, state and local regulatory efforts continue to focus on potential climate change or GHG emissions regulation, and mandatory GHG reporting requirements have become effective in both Canada and the United States. Mandatory GHG emissions reductions requirements are expected to impose increased costs on our business, as is expected to be the case generally for thermal power producers in North America. We are subject to other air quality regulations including mercury regulations. To the extent new or additional GHG, mercury or other air emission regulations may require us to incur costs that cannot be passed through to our customers under its power purchase agreements, including Alberta PPAs or otherwise, the costs could be material and have a material adverse effect on our business. In terms of TransAlta's existing gas-fired facilities, we currently have change-in-law provisions allowing flow-through of carbon tax-related costs, and we expect that any new contracts will contain similar provisions.

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

We may be unsuccessful in the defence of legal actions.

We are occasionally named as a defendant in claims and legal actions and as a party in commercial disputes which are resolved by arbitration. There can be no assurance that we will be successful in the defence of these claims and legal actions or that any claim or legal action that is decided adverse to us will not materially and adversely affect us.

Unexpected changes in the cost of maintenance or in the cost and durability of components for the Corporation's facilities may adversely affect its results of operations.

Unexpected increases in the Corporation's cost structure that are beyond the control of the Corporation could materially adversely impact its financial performance. Examples of such costs include, but are not limited to: unexpected increases in the cost of procuring materials and services required for maintenance activities, and unexpected replacement or repair costs associated with equipment underperformance or lower-than-anticipated durability.

Equipment failure may cause us to suffer a material adverse effect.

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

We may fail to meet financial expectations.

Our quarterly revenue and results of operations are difficult to predict and fluctuate from quarter to quarter. Our quarterly results of operations are influenced by a number of factors, including the risks described in this AIF, many of which are outside of our control, which may cause such results to fall below market expectations.

Although we base our planned operating expenses in part on our expectations of future revenue, a significant portion of our expenses are relatively fixed in the short-term. If revenue for a particular quarter is lower than expected, we likely will be unable to proportionately reduce our operating expenses for that quarter, which will adversely affect our results of operations for that quarter.

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

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

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

A natural or man-made disaster, and certain other events, including natural or induced seismic activity, could potentially cause dam failures at our hydroelectric facilities. The occurrence of dam or dyke failures at any of our hydroelectric or coal facilities could result in a loss of generating capacity, damage to the environment or damages and harm to third parties or the public, and such failures could require us to incur significant expenditures of capital and other resources or expose us to significant liabilities for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Reinforcing all dams or dykes to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam failures could have a material adverse effect on us.

We may be adversely affected if our supply of water is materially reduced.

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

Variation in wind levels may negatively impact the amount of electricity generated at our wind facilities.

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

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

Changes in the price of electricity and availability of fuel supplies required to generate electricity may materially adversely affect our business.

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

We buy natural gas and a portion of our coal to supply the fuel needed to generate electricity. We could be materially adversely affected if the cost of fuel that we must buy to generate electricity increases to a greater degree than the price that we can obtain for the electricity that we sell. Several factors affect the price of fuel, many of which are beyond our control, including:

- prevailing market prices for fuel;
- global demand for energy products;
- the cost of carbon and other environmental concerns;
- weather-related disruptions affecting the ability to deliver fuels or near-term demand for fuels;
- increases in the supply of energy products in the wholesale power markets;
- the extent of fuel transportation capacity or cost of fuel transportation service into our markets; and
- the cost of mining that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

Changes in any of these factors may increase our cost of producing power or decrease the amount of revenue received from the sale of power, which could have a material adverse effect on us.

Disruption of fuel supply to certain of our thermal plants could have an adverse impact on our financial condition.

Certain of our thermal facilities depend on third parties to supply fuel, including natural gas and coal. As a result, we face the risks of supply interruptions and fuel price volatility, as fuel deliveries may not exactly match those required for energy sales, due in part to our need to pre-purchase fuel inventories for reliability and dispatch requirements. Disruption of transportation services of fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of locks and dams or other events could impair our ability to generate electricity and could adversely affect our results of operations. Significantly, the coal used to fuel the Centralia Thermal facility is now sourced from the Powder River Basin in Montana and Wyoming and we have entered into contracts to purchase and transport such coal to our Centralia Thermal facility. Our existing coal contracts for the Centralia Thermal plant expire between 2017 and 2025. The loss of our suppliers or our inability to renew our existing coal contracts for Powder River Basin coal at favourable terms could also significantly affect our ability to serve our customers and have an adverse impact on our financial condition and results of operations.

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

Adverse changes in general economic and market conditions and, more specifically, in the markets in which we operate could negatively impact demand for electricity, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, credit risk and counterparty risk, which could cause us to suffer a material adverse effect. Changes in interest rates can impact our borrowing costs and the capacity revenues that we receive pursuant to the Alberta PPAs.

There are risks associated with our Alberta PPAs.

Under the government-mandated Alberta PPAs, pursuant to which we operate most of our thermal and hydroelectric facilities in Alberta, we are subject to certain risks, including the possibilities of penalties for unplanned outages and the burden of increased costs required to maintain and operate our generation facilities.

The Alberta PPAs establish committed capacity and Availability targets to be achieved by each coal-fired plant, energy and ancillary services obligations for the hydroelectric plants, and compensation for meeting the Alberta PPA obligations. Under the Alberta PPAs applicable to coal-fired plants, in the event of an unplanned outage other than an outage determined to be caused by *force majeure*, we must pay a penalty for the lost production based upon a price equal to the 30 day trailing average of Alberta market electricity prices. Consequently, an unplanned outage could have a material adverse effect on us.

We bear some of the impact of increases in our operating costs (other than increases arising as a result of a “change in law” as such term is defined in the Alberta PPAs) because the price which we are able to receive for our capacity under the Alberta PPAs is based on a schedule of

forecast fixed costs. Many of the forecast costs will be determined by indices, formulae or other means for the entire term of the Alberta PPAs. Our actual results will vary from the forecasts on which the Alberta PPAs are based. Operating costs could increase as a result of a number of factors which are beyond our control. A significant increase in our operating costs could have a material adverse effect on our business. In addition, there can be no assurance that we will realize sufficient returns under the Alberta PPAs to cover the capital costs we are required to invest under such PPAs.

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

A power purchaser under an Alberta PPA is permitted to return the Alberta PPA to the Balancing Pool in certain circumstances, including as a result of a change in law that renders the Alberta PPA unprofitable to the power purchaser. In early 2016, the buyers gave notice to the Balancing Pool of the termination of the Alberta PPAs for Sundance A, B and C, Sheerness and Keephills. The Balancing Pool confirmed the termination of such Alberta PPAs, with the exception of Keephills. Following such terminations the Balancing Pool is able to resell, hold or terminate such Alberta PPA in certain circumstances. If the Balancing Pool exercises its ability to terminate an Alberta PPA in respect of a unit that we own, we would be entitled to receive payment equal to the remaining closing net book value of the generating unit. The termination payment by the Balancing Pool could be less than the economic value of the generating unit, which could have a material adverse effect on the Corporation.

The market price for our common shares may be volatile.

The market price for our common shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond our control, including the following: (a) actual or anticipated fluctuations in our results of operations; (b) recommendations by securities research analysts; (c) changes in the economic performance or market valuations of other companies that investors deem comparable; (d) the loss or resignation of executive officers and other key personnel; (e) sales or perceived sales of additional common shares; (f) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving our competitors which prove to be ill considered; and (g) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the power generation industry or our target markets.

Financial markets have experienced significant price and volume fluctuations in recent years that have particularly affected the market prices of equity securities of companies and such fluctuations have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of our common shares may decline even if our operating results, underlying asset values or prospects

have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values which may result in impairment losses. Certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in our common shares by those institutions, which could adversely affect the trading price of our common shares.

Our cash dividend payments are not guaranteed.

The payment of dividends is not guaranteed and could fluctuate. The Board has the discretion to determine the amount of dividends to be declared and paid to shareholders. We may alter our dividend policy at any time and the payment of dividends will depend on, among other things, results of operations; financial condition; current and expected future levels of earnings; operating cash flow; liquidity requirements; market opportunities; income taxes; maintenance and growth capital expenditures; debt repayments; legal, regulatory and contractual constraints; working capital requirements; tax laws and other relevant factors. Our short and long-term borrowings may prohibit us from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of any dividends we may pay in the future. If we continue to pay dividends at the current level, we may not retain a sufficient amount of cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund our operations in the event of a significant business downturn. The Board, subject to the requirements of our bylaws and other governance documents, may amend, revoke or suspend our dividend policy at any time. A decline in the market price or liquidity, or both, of our common shares could result if the Board establishes large reserves that reduce the amount of quarterly dividends paid or if we reduce or eliminate the payment of dividends.

We will be dependent on the operations of our facilities for our cash availability. The actual amount of cash available for dividends to holders of our common shares will depend upon numerous factors relating to each of our generation facilities including: operating performance of our generation facilities, profitability, changes in revenues, fluctuations in working capital, capital expenditure levels, applicable laws, compliance with contracts and contractual restrictions contained in the instruments governing any indebtedness. Any reduction in the amount of cash available for distribution from our generation facilities will reduce the amount of cash available to pay dividends to holders of our common shares.

We operate in a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the United States and Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity and international conglomerates. Some competitors have significantly greater financial and other resources than we do. Competitive harm could have a material adverse effect on our business.

We could suffer lost revenues or increased expenses and penalties if we are unable to operate our generation facilities at a level

necessary to comply with our PPAs.

The ability of our facilities to generate the maximum amount of power which can be sold under PPAs is an important determinant of our revenues. Under certain PPAs, if the facility is made available less than the required Availability in a given contract year, penalty payments may be payable to the relevant purchaser by us. The payment of any such penalties could adversely affect our revenues and profitability.

Our revenues may be reduced upon expiration or termination of PPAs.

We sell power under PPAs that expire at various times. In addition, these PPAs may be subject to termination in certain circumstances, including default by the facility or plant owner or operator. When a PPA expires or is terminated, it is possible that the price received by the relevant facility or plant for power under subsequent selling arrangements may be reduced significantly. It is also possible that to the extent a PPA is negotiated after the initial

PPAs have run their course, the new contract may not be available at prices that permit the continued operation of the affected facility or plant on a profitable basis. If this occurs, the affected facility or plant may be forced to permanently cease operations.

Variations in weather can affect demand for electricity and our ability to generate electricity.

Due to the nature of our business, our earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar farm.

Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on wind turbine blades depends on a number of factors, including temperature, and ambient humidity. The accumulation of ice on wind turbine blades can have a significant impact on energy yields, and could result in the wind turbine experiencing more down time. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production.

In addition, climate change could result in increased variability to our water and wind resources.

The laws and regulations in the various markets in which we operate are subject to change, which may materially adversely affect us.

Certain of the markets in which we operate and intend to operate are subject to significant regulatory oversight and control. We are not able to predict whether there will be any further changes in the regulatory environment, including potential regulation of the rates allowed to be charged and the capital structure of wholesale generating companies such as ours, changes in market structure or market design or what the ultimate effect of a changing regulatory environment will have on our business. Existing market rules, regulations and reliability standards are often dynamic and may be revised or re-interpreted and new laws and regulations may be adopted or become applicable to us or our facilities, which could have a material adverse effect on us.

We manage these risks systematically through a regulatory and compliance program designed to reduce any potential negative impact on us. However, we cannot guarantee that we will be able to adapt our business in a timely manner in response to any changes in the regulatory regimes in which we operate, and such failure to adapt could have a material adverse effect on our business.

Regulatory authorities may also from time to time audit or investigate our activities in the markets in which we operate or pursue trading. Such audits or investigations may result in sanctions or penalties which may materially affect our future activities, our reputation or our financial status.

Our facilities are also subject to various licensing and permitting requirements in the jurisdictions in which we operate. Many of these licenses and permits need to be renewed from time to time. If we are unsuccessful in renewing such licenses or permits, or the terms of such licenses or permits are changed in a manner that is adverse to our business, we could be materially adversely affected.

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

Changes in opinions of our Corporation from external parties may have a material adverse effect on us.

Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments and other entities. Our reputation is one of our most valued assets. The potential for harming our reputation exists in every business decision and all risks can have an impact on reputation, which in turn can negatively impact our business and securities. Reputational risk cannot be managed in isolation from other forms of risk. Negative impacts from a compromised reputation could include revenue loss, reduction in customer base, and decreased value of our securities.

We depend on certain partners that may have interests or objectives which conflict with our objectives and such differences could have a negative impact on us.

We have entered into various types of arrangements with communities or joint venture partners for the operation of our facilities. Certain of these partners may have or develop interests or objectives which are different from or even in conflict with our objectives. Any such differences could

have a negative impact on the success of our facilities. We are sometimes required through the permitting and approval process to notify and consult with various stakeholder groups, including landowners, First Nations and municipalities. Any unforeseen delays in this process may negatively impact our ability to complete any given facility on time or at all.

We are dependent on access to parts and equipment from certain key suppliers and we may be adversely affected if these relationships are not maintained.

Our ability to compete and expand will be dependent on having access, at a reasonable cost, to equipment, parts and components which are technologically and economically competitive with those utilized by our competitors. Although we have individual framework agreements with various suppliers, there can be no assurance that these relationships with suppliers will be maintained. If they are not maintained, our ability to compete may be impaired due to lack of access to these sources of equipment, parts or components.

Our information technology systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyber-attack and other similar disruptions, all of which could have a material adverse effect on our business.

We rely on technology, mainly on computer, telephone, satellite, cellular and related networks and infrastructure, to conduct our business and monitor the production of our generation facilities. These systems and infrastructure could be vulnerable to unforeseen problems including, but not limited to, vandalism and theft. We have put in place a number of systems, processes, practices and data backups designed to protect against intentional or unintentional misappropriation or corruption of our systems and information or disruption of our operations. Despite our implementation of security measures, our information technology systems are vulnerable to damages from computer viruses, natural disasters, unauthorized access, cyber-attack and other similar disruptions.

Any damage or failure that causes an interruption in operations could have an adverse effect on our customers. Additionally, we protect our generation facility infrastructure against physical damage, security breaches and service disruption from any of a variety of causes. Theft, vandalism, and other disruptions could jeopardize the security of information stored in and transmitted through our systems and network infrastructure, and could result in significant set-backs, potential liabilities, and deter future customers. While we have systems, policies, hardware, practices, data backups and procedures designed to prevent or limit the effect of the failure, interruptions or security breaches of our generation facility and infrastructure, there can be no assurance that these measures will be sufficient and that such failures, interruptions or security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

Cyber-attacks may cause disruptions to our operations and could have a material adverse effect on our business.

We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. Cyber-attacks or other breaches of network or information technology systems security may cause disruptions to our operations. Cyber attackers may use a range of techniques, from manipulating people to using sophisticated malicious software and hardware on a single or distributed basis. Some cyber attackers use a combination or techniques in their attempt to evade safeguards, such as firewalls, intrusion prevention systems and antivirus software found in our systems and networks. A successful attack on our systems, networks and infrastructure may allow for the unauthorized interception, destruction, use or dissemination of our information and may cause disruptions to our operations.

We take measures to secure our infrastructure against potential cyber-attacks that may damage our infrastructure, systems and data. Our cyber security program aligns with industry best practices to ensure that a holistic approach to

security is maintained. We have implemented security controls to help secure our data and business operations including: access control measures, intrusion detection and prevention systems, logging and monitoring of network activities, and implementing policies and procedures to ensure the secure operations of the business.

While we have systems, policies, hardware, practices, data backups and procedures designed to prevent or limit the effect of the security breaches of our generation facility and infrastructure, there can be no assurance that these measures will be sufficient and that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

Our facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.

Our power generation facilities depend on electric transmission systems and related facilities owned and operated primarily by third parties to deliver the electricity that we generate to delivery points where ownership changes and we are paid. These grids operate with both regulatory and physical constraints which in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which our power generation facilities are physically disconnected from the power grid, or our production curtailed, for short periods of time. Most of our electricity sales contracts do not provide for payments to be made if electricity is not delivered.

Our power generation facilities may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which our power generation facilities are connected. Our power generation facilities in the future may not be able to secure access to this interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate PPAs or to construct new projects. In addition, we may not benefit from preferential arrangements in the future. Any such increased costs and delays could delay the commercial operation dates of any new projects and negatively impact our revenues and financial condition.

Trading risks may have a material adverse effect on our business.

Our trading and marketing business frequently involves the establishment of trading positions in the wholesale energy markets on both a medium-term and short-term basis. To the extent that we have long positions in the energy markets, a downturn in market prices will result in losses from a decline in the value of such long positions. Conversely, to the extent that we enter into forward sales contracts to deliver energy that we do not own, or take short positions in the energy markets, an upturn in market prices will expose us to losses as we attempt to cover any short positions by acquiring energy in a rising market.

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

If the strategy that we use to hedge our exposures to these various risks is not effective, we could incur significant losses. Our trading positions can be impacted by volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short-term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect our positions which could also have a material adverse effect on our business.

We use a number of risk management controls conducted by our independent Risk Management group in order to limit our exposure to risks arising from our trading activities. These controls include risk capital limits, VaR, GMaR, tail risk scenarios, position limits, concentration limits, credit limits, and approved product controls. We cannot guarantee that losses will not occur and such losses may be outside the parameters of our risk controls.

Because of our multinational operations, we are subject to currency rate risk and regulatory and political risk.

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services from foreign suppliers, and our U.S. denominated debt. Our exposures are primarily to the U.S. and Australian currencies. Changes in the values of these currencies relative to the Canadian dollar could negatively impact our earnings or the value of our foreign investments. While we attempt to manage this risk through the use of hedging instruments, including cross-currency interest rate swaps, forward exchange contracts and matching revenues and expenses by currency at the Corporate level, there can be no assurance that these risk management efforts will be effective, and fluctuations in these exchange rates may have a material adverse effect on our business.

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

We may have difficulty raising needed capital in the future, which could significantly harm our business.

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

Recovery of the capital investment in power projects generally occurs over a long period of time. As a result, we must obtain funds from equity or debt financings, including tax equity transactions, or from government grants, to help finance the acquisition of projects and to help pay the general and administrative costs of operating our business. Our ability to arrange financing, either at the corporate level or at the subsidiary level (including non-recourse project debt), and the costs of such capital are dependent on numerous factors, including: (a) general economic and capital market conditions; (b) credit availability from banks and other financial institutions; (c) investor confidence and the markets in which we conduct operations; (d) our financial performance; (e) our level of indebtedness and compliance with covenants in our debt agreements; and (f) our cash flow.

An increase in interest rates or a reduction in the availability of project debt financing could reduce the number of projects that we are able to finance. If we are unable to raise additional funds when needed, we could be required to delay acquisition and construction of projects, reduce the scope of projects, abandon or sell some or all of our projects or generation facilities, or default on our contractual commitments in the future, any of which could adversely affect our business, financial condition and results of operations.

TransAlta Corporation's debt securities will be structurally subordinated to any debt of our subsidiaries that are currently outstanding or may be incurred in the future.

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

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

Our subsidiaries have financed some investments using non-recourse project financing. Each non-recourse project loan is structured to be repaid out of cash flow provided by the investment. In the event of a default under a financing agreement which is not cured, the lenders would generally have rights to the related assets. In the event of foreclosure after a default, our subsidiary may lose its equity in the asset or may not

be entitled to any cash that the

asset may generate. Although a default under a project loan will not cause a default with respect to any debt securities issued by TransAlta, it may materially affect our ability to service our outstanding indebtedness.

A downgrade of our credit ratings could materially and adversely affect us.

Rating agencies regularly evaluate us, basing their ratings of our long-term and short-term debt on a number of factors. There can be no assurance that one or more of our credit ratings and the corresponding outlook will not be changed. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions with us. A credit rating downgrade could potentially impair our ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit our access to private and public credit markets and increase the costs of borrowing under our existing credit facilities. A credit rating downgrade could require us to post a material amount of new collateral to our counterparties. For further information on posting collateral, please see Note 14 section C. III of our audited consolidated financial statements for the year ended December 31, 2016, which financial statements are incorporated by reference herein. Please also see "*Documents Incorporated by Reference*" in this AIF.

Changes in statutory or contractual restrictions may have an adverse effect on our ability to service debt obligations.

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

The power generation industry has certain inherent risks related to worker health and safety and the environment that could cause us to suffer unanticipated expenditures or to incur fines, penalties or other consequences material to its business and operations.

The ownership and operation of our power generation assets carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licenses, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licenses, permits and other approvals are expected to remain material to our business. The occurrence of any of these events or any changes, additions to, or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on our operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to our business and operations.

Certain of the contracts to which we are a party require that we provide collateral against our obligations.

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

If counterparties to our contracts are unable to meet their obligations, we may be materially and adversely affected.

If purchasers of our electricity and steam or other contractual counterparties default on their obligations, we may be materially and adversely affected. While we have procedures and controls in place to manage our counterparty

credit risk prior to entering into contracts, all contracts inherently contain default risk. Moreover, while we seek to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, we cannot guarantee that a party will not default. If counterparties to our contracts are unable to meet their obligations, we could suffer a reduction in revenue which could have a material adverse effect on our business.

We are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our business is exposed to the risks inherent in the construction and operation of electricity generation facilities, such as breakdowns, manufacturing defects, natural disasters, theft, terrorist attacks and sabotage. We are also exposed to environmental risks. We maintain insurance policies, covering usual and customary risks associated with our business, with credit worthy insurance carriers. Our insurance policies, however, do not cover losses as a result of *force majeure*, natural disasters, terrorist or cyber attacks or sabotage, among other things. In addition, we generally do not maintain insurance for certain environmental risks, such as environmental contamination. Our insurance policies are subject to annual review by the respective insurers and may not be renewed at all or on similar or favourable terms. A significant uninsured

loss or a loss significantly exceeding the limits of our insurance policies or the failure to renew such insurance policies on similar or favourable terms could have a material adverse effect on our business, financial condition and results of operations.

Our insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for any loss or damage to any of our generation facilities may not be sufficient to permit us to continue to make payments on our debt.

Provision for income taxes may not be sufficient.

Our operations are complex, and the computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. In addition, our tax filings are subject to audit by taxation authorities. While we believe that our tax filings have been made in material compliance with all applicable tax interpretations, regulations, and legislation, we cannot guarantee that we will not have disagreements with taxation authorities with respect to our tax filings that could have a material adverse effect on our business.

The Corporation and its subsidiaries are subject to changing laws, treaties and regulations in and between countries. Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense which could have a material adverse impact on the Corporation.

If we fail to attract and retain key personnel, we could be materially adversely affected.

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

If we are unable to successfully negotiate new collective bargaining agreements with our unionized workforce, as required from time to time, we will be adversely affected.

While we believe we have a satisfactory relationship with our unionized employees, we cannot guarantee that we will be able to successfully negotiate or renegotiate our collective bargaining agreements on terms agreeable to TransAlta. We expect to re-negotiate four collective bargaining agreements, involving 385 of our employees, in 2017. Four collective bargaining agreements representing a total of 160 employees are anticipated to be negotiated in 2018. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

Risks relating to TransAlta's development projects and acquisitions may materially and adversely affect us.

Development projects and acquisitions that we undertake may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third party opposition, cost escalations,

construction delays, shortages of raw materials or skilled labour and capital constraints. The occurrences of these risks could have a material and adverse impact on us, our financial condition, results of operations and cash flows.

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

We may pursue acquisitions in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to us currently, which may adversely affect our ability to receive revenues or enforce our rights in connection with any such foreign operations. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the projects that we may acquire, thus limiting our ability to control the operation of such projects. Any existing or new operations may also be subject to significant political, economic and financial risks, which vary by country, and may include: (a) changes in government policies or personnel; (b) changes in general economic conditions; (c) restrictions on currency transfer or convertibility; (d) changes in labour relations; (e) political instability and civil unrest; (f) regulatory or other changes in the local electricity market; and (g) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

With respect to acquisitions, we cannot make assurances that we will identify suitable transactions or that we will have access to sufficient resources, through our credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition that we propose or complete would be subject to normal commercial risks that the transaction may not be completed on the terms negotiated, on time, or at all. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on our business, financial condition, results of operations and cash flows.

EMPLOYEES

As of December 31, 2016, we had 2,341 active employees, which figure includes full-time, part-time and temporary employees, of which 1,197

were employed in our Canadian Coal segment (including our SunHills mining operation), 208 were employed in our U.S. coal segment, 240 were employed in our Gas Segment, 96 were employed in our Wind and Solar business, 97 were employed in our Hydro business, 70 were employed in our Energy Marketing business, and the remaining employees were employed in our Corporate segment. Approximately 53 per cent of our employees are represented by labour unions. We are currently a party to 11 different collective bargaining agreements. In 2016, we renewed three of the collective bargaining agreements.

CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of common shares and an unlimited number of first preferred shares, issuable in series. As at March 2, 2017, there were 287,903,467 common shares outstanding and 10,175,380 Series A Shares, 1,824,620 Series B Shares, 11,000,000 Series C Shares, 9,000,000 Series E Shares and 6,600,000 Series G Shares outstanding. The Corporation does not have any escrowed securities.

Common Shares

Each common share of TransAlta Corporation entitles the holder thereof to one vote for each common share held at all meetings of shareholders of the Corporation, except meetings at which only holders of another specified class or series of shares are entitled to vote, to receive dividends if, as and when declared by the Board, subject to prior satisfaction of preferential dividends applicable to any first preferred shares, and to participate rateably in any distribution of our assets upon a liquidation, dissolution or winding up and subject to prior rights and privileges

attaching to first preferred shares. The common shares are not convertible and are not entitled to any pre-emptive rights. The common shares are not entitled to cumulative voting.

On January 14, 2016, we announced the suspension of the Premium Dividend ™, Dividend Reinvestment and Optional Common Share Purchase Plan.

First Preferred Shares

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

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

The Board may include, in the share conditions attaching to a particular series of first preferred shares, certain voting rights effective upon our failing to make payment of six quarterly dividend payments, whether or not consecutive. These voting rights continue for so long as any dividends remain in arrears. These voting rights are the right to one vote for each $25.00 of subscription price on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of TransAlta if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

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

Series A Shares

12.0 million Series A Shares were issued on December 10, 2010 with a coupon of 4.60 per cent, for gross proceeds of $300 million. On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares. Certain provisions of the Series A Shares are discussed below.

Dividends on Series A Shares

The holders of Series A Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a “Subsequent Fixed Rate Period”), the holders of Series A Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March,

June, September and December in each year, in the amount

per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares and the Series B Shares described below, and will remain unchanged over the life of the Series A Shares.

Redemption of Series A Shares

The Series A Shares are redeemable by TransAlta, at its option, in whole or in part, on March 31, 2016, and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series A Shares of the redemption of all of the Series A Shares, the right of a holder of Series A Shares to convert such Series A Shares shall terminate and we shall not be required to give notice to the registered holders of the Series A Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series A Shares.

Conversion of Series A Shares into Series B Shares

The holders of the Series A Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series B of TransAlta (the "Series B Shares"), subject to certain conditions, on March 31, 2016 and on March 31 in every fifth year thereafter. The holders of the Series B Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate (the "T-Bill Rate") (which means, the average yield expressed as an annual rate on the 90 day Government of Canada treasury bill, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable Floating Rate Calculation Date) on the applicable date and 2.03 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 2.03 per cent.

The Series A Shares and Series B Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series A Shares and Series B Shares are identical in all material respects.

On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares.

Voting Rights

The holders of the Series A Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series A Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series A Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series A Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required

by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation

Modification

The provisions attaching to the Series A Shares as a class may be amended with the written approval of all the holders of Series A Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series B Shares

1,824,620 Series B Shares were issued on March 31, 2016. Certain provisions of the Series B Shares are discussed below.

Dividends on Series B Shares

The holders of Series B Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, floating rate cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after conversion, the holders of Series B Shares shall be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate (the "T-Bill Rate") (which means, the average yield expressed as an annual rate on the 90 day Government of Canada treasury bill, as reported by the Bank of Canada, for the most recent treasury bills auction preceding the applicable Floating Rate Calculation Date) on the applicable date and 2.03 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 2.03 per cent. This spread will apply to both the Series A Shares described above and the Series B Shares and will remain unchanged over the life of the Series B Shares.

Redemption of Series B Shares

The Series B Shares are redeemable by TransAlta, at its option, in whole or in part, on March 31, 2021 and on March 31 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series B Shares of the redemption of all of the Series B Shares, the right of a holder of Series B Shares to convert such Series B Shares shall terminate and we shall not be required to give notice to the registered holders of the Series B Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series B Shares.

Conversion of Series B Shares into Series A Shares

The holders of the Series B Shares have the right to convert all or any of their shares into cumulative redeemable fixed rate first preferred shares, Series A of TransAlta (the "Series A Shares"), subject to certain conditions, on March 31, 2021 and on March 31 in every fifth year thereafter. The holders of the Series A Shares will be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends payable on the last day

of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 2.03 per cent.

The Series A Shares and Series B Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series A Shares and Series B Shares are identical in all material respects.

Voting Rights

The holders of the Series B Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series B Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series B Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series B Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation

Modification

The provisions attaching to the Series B Shares as a class may be amended with the written approval of all the holders of Series B Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series C Shares

11.0 million cumulative redeemable rate reset first preferred shares, Series C (the "Series C Shares") were issued on November 30, 2011, with a coupon of 4.60 per cent, for gross proceeds of $275 million as discussed in the section entitled "*General Development of the Business*". Certain provisions of the Series C Shares are discussed below.

Dividends on Series C Shares

The holders of Series C Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series C Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five-year bond) on the Fixed Rate Calculation Date plus a spread of 3.10 per cent. This spread will apply to both the Series C Shares and the Series D Shares described below, and will remain unchanged over the life of the Series C Shares.

Redemption of Series C Shares

The Series C Shares are redeemable by TransAlta, at its option, in whole or in part, on June 30, 2017, and on June 30 in every fifth year thereafter by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series C Shares of the redemption of all of the Series C Shares, the right of a holder of Series C Shares to convert such Series C Shares shall terminate and we shall not be required to give notice to the registered holders of the Series C Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series C Shares.

Conversion of Series C Shares into Series D Shares

The holders of the Series C Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series D of TransAlta (the "Series D Shares"), subject to certain conditions, on June 30, 2017 and on June 30 in every fifth year thereafter. The holders of the Series D Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.10 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.10 per cent.

The Series C Shares and Series D Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series C Shares and Series D Shares are identical in all material respects.

Voting Rights

The holders of the Series C Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series C Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series C Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series C Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series C Shares as a class may be amended with the written approval of all the holders of Series C Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series E Shares

9.0 million cumulative redeemable rate reset first preferred shares, Series E (the "Series E Shares") for gross proceeds of $225 million, as discussed in the section entitled "*General Development of the Business*". Certain provisions of the Series E Shares are discussed below.

Dividends on Series E Shares

The holders of Series E Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September, and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series E Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta Corporation on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five-year bond) on the Fixed Rate Calculation Date plus a spread of 3.65 per cent. This spread will apply to both the Series E Shares and the Series F Shares described below, and will remain unchanged over the life of the Series E Shares.

Redemption of Series E Shares

The Series E Shares are redeemable by TransAlta Corporation, at its option, in whole or in part, on September 30, 2017, and on September 30 in every fifth year thereafter by the payment of an amount of $25.00 in cash for each share to be redeemed plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series E Shares of the redemption of all of the Series E Shares, the right of a holder of Series E Shares to convert such Series E Shares shall terminate and we shall not be required to give notice to the registered holders of the Series E Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series E Shares.

Conversion of Series E Shares into Series F Shares

The holders of the Series E Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series F of TransAlta (the "Series F Shares"), subject to certain conditions, on September 30, 2017 and on September 30 in every fifth year thereafter. The holders of the Series F Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred-thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.65 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the

dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.65 per cent.

The Series E Shares and Series F Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series E Shares and Series F Shares are identical in all material respects.

Voting Rights

The holders of the Series E Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series E Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series E Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series E Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series E Shares as a class may be amended with the written approval of all the holders of Series E Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

Series G Shares

6.6 million cumulative redeemable rate reset first preferred shares, Series G (the "Series G Shares") for gross proceeds of $165 million, as discussed in the section entitled "*General Development of the Business*". Certain provisions of the Series G Shares are discussed below.

Dividends on Series G Shares

The holders of Series G Shares are entitled to receive, as and when declared by the Board out of moneys of TransAlta properly applicable to the payment of dividends, fixed cumulative preferential cash dividends payable quarterly on the last day of March, June, September, and December in each year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of Series G Shares shall be entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly on the last day of March, June, September and December in each year, in the amount per share determined by multiplying one-quarter of the Annual Fixed Dividend Rate for such Subsequent Fixed Rate Period by $25.00 (less any tax that we are required to deduct and withhold). The Annual Fixed Dividend Rate for the ensuing Subsequent Fixed Rate Period will be determined by TransAlta Corporation on the Fixed Rate Calculation Date (30th day prior to the first day of such Subsequent Fixed Rate Period) and will be equal to the sum of the Government of Canada Yield (yield to maturity of a Government of Canada non-callable five year bond) on the Fixed Rate Calculation Date plus a spread of 3.80 per cent. This spread will apply to both the Series G Shares and the Series H Shares described below, and will remain unchanged over the life of the Series G Shares.

Redemption of Series G Shares

The Series G Shares are redeemable by TransAlta Corporation, at its option, in whole or in part, on September 30, 2019, and on September 30 in every fifth year thereafter by the payment of an amount of $25.00 in cash for each share to be redeemed plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax that we are required to deduct and withhold).

If we give notice to the holders of the Series G Shares of the redemption of all of the Series G Shares, the right of a holder of Series G Shares to convert such Series G Shares shall terminate and we shall not be required to give notice to the registered holders of the Series G Shares of an Annual Fixed Dividend Rate, a Floating Quarterly Dividend Rate or the conversion right of holders of Series G Shares.

Conversion of Series G Shares into Series H Shares

The holders of the Series G Shares have the right to convert all or any of their shares into cumulative redeemable floating rate first preferred shares, Series H of TransAlta (the "Series H Shares"), subject to certain conditions, on September 30, 2019 and on September 30 in every fifth year thereafter. The holders of the Series H Shares will be entitled to receive, as and when declared by the Board, quarterly floating rate cumulative preferential cash dividends payable on the last day of March, June, September, and December in each year (each such quarterly dividend period is referred to as a "Quarterly Floating Rate Period"), in the amount per share determined by multiplying the "Floating Quarterly Dividend Rate" (which means, for any Quarterly Floating Rate Period, the annual rate of interest, (expressed as a percentage and rounded to the nearest one hundred thousandth of one per cent), equal to the sum of the T-Bill Rate on the applicable date and 3.80 per cent) for such Quarterly Floating Rate Period by $25.00 and multiplying that product by a fraction, the numerator of which is the actual number of days in such Quarterly Floating Rate Period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year (less any tax that we are required to deduct and withhold). If any such date is not a business day, the dividend will be paid on the next succeeding business day. The Floating Quarterly Dividend Rate will be the annual rate of interest equal to the sum of the T-Bill Rate on the applicable Floating Rate Calculation Date plus a spread of 3.80 per cent.

The Series G Shares and Series H Shares are series of shares in the same class. The conversion right entitles holders to elect periodically which of the two series they wish to hold and does not entitle holders to receive a different class or type of securities. Other than the different dividend rights and redemption rights attached thereto, the Series G Shares and Series H Shares are identical in all material respects.

Voting Rights

The holders of Series G Shares are not entitled to any voting rights or to receive notice of or to attend shareholders' meetings unless dividends on the Series G Shares are in arrears to the extent of six quarterly dividends, whether or not consecutive. Until all arrears of dividends have been paid, holders of Series G Shares will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class or series of shares) and to one vote in respect of each Series G Share held on all matters in respect of which shareholders vote, and additionally, the right of all series of first preferred shares, voting as a combined class, to elect two directors of the Corporation if the Board then consists of less than 16 directors, or three directors if the Board consists of 16 or more directors. Otherwise, except as required by law, the holders of first preferred shares shall not be entitled to vote or to receive notice of or attend any meeting of the shareholders of the Corporation.

Modification

The provisions attaching to the Series G Shares as a class may be amended with the written approval of all the holders of Series G Shares outstanding or by at least two-thirds of the votes cast at a meeting of the holders of such shares duly called for the purpose and at which a quorum is present.

CREDIT RATINGS

The following information concerning our credit ratings is provided as it relates to our financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. Additionally, our ability to engage in certain collateralized business activities on a cost effective basis depends on our credit ratings. A reduction in the current rating on our debt by our rating

agencies, particularly a downgrade below investment grade ratings, or a negative change in our ratings outlook could adversely affect our cost of financing and access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require us to post additional collateral under certain of our contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	DBRS	Fitch	Moody's	S&P
Issuer Rating	BBB	BBB-	Not Applicable	BBB-
Corporate Family Rating	Not Applicable	Not Applicable	Ba1	Not Applicable
Preferred Shares	Pfd-3[(1)]	Not Applicable	Not Applicable	P-3[(1)]
Unsecured Debt/MTNs	BBB	BBB-	Ba1/LGD4	BBB-
Rating Outlook	Negative	Negative	Stable	Stable

Note:
[(1)] The outstanding Preferred Shares all have the same rating.

On December 17, 2015, TransAlta Corporation was downgraded to Ba1 (stable) by Moody's and Moody's also assigned the Corporation a Ba1 Corporate Family rating. As expected, the direct financial impact of this downgrade has been limited. We have posted additional collateral to certain counterparties, and the cost of borrowing under US$400 million of debt and our credit facilities has been stepped-up in line with contractual provisions. The Corporation maintains investment grade ratings from three credit rating agencies including BBB- (stable outlook) by S&P, BBB (negative outlook) by DBRS and BBB- (negative outlook) by Fitch.

DBRS

DBRS Corporate rating analysis begins with an evaluation of the fundamental creditworthiness of the issuer, which is reflected in an "issuer rating". Issuer ratings address the overall credit strength of the issuer. Unlike ratings on individual securities or classes of securities, issuer ratings are based on the entity itself and do not include consideration for security or ranking. Ratings that apply to actual securities (secured or unsecured) may be higher, lower or equal to the issuer rating for a given entity. As of December 31, 2016, our issuer rating was BBB (negative) from DBRS. A BBB rating is the fourth highest out of ten categories.

The DBRS preferred share rating scale is used in the Canadian securities market and is meant to give an indication of the risk that a borrower will not fulfill its full obligations in a timely manner, with respect to both dividend and principal commitments. Every DBRS rating is based on quantitative and qualitative considerations relevant to the borrowing entity. Each rating category is denoted by the subcategories "high" and "low". The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. Preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Each of the Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares have been rated Pfd-3 (negative) by DBRS. The Pfd-3 rating is the third highest out of six categories.

The DBRS long-term rating scale provides an opinion on the risk of default. That is, the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings

are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)". The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. Debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. As of December 31, 2016, our senior unsecured long-term debt is rated BBB (negative) by DBRS. The BBB rating category is the third highest of ten categories for long term obligations.

Fitch

As of December 31, 2016, our Fitch long term Issuer Default Rating (IDR) and senior unsecured rating was BBB- with a negative outlook. The Fitch rating system describes a BBB rating as good credit quality. 'BBB' ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate but adverse business or economic conditions are more likely to impair this capacity. The modifiers + or - may be appended to a rating to denote relative status within major rating categories. Such suffixes are added to Long-Term Issuer Default Ratings between AA and B. A BBB rating is the fourth highest of 11 rating categories.

Ratings of individual securities or financial obligations of a corporate issuer address relative vulnerability to default on an ordinal scale. As of December 31, 2016, our senior unsecured rating was BBB-. The Fitch rating system describes a BBB rating as good credit quality. 'BBB' ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate but adverse business or economic conditions are more likely to impair this capacity. The modifiers + or - may be appended to a rating to denote relative status within major rating categories. Such suffixes are added to obligation rating categories, or to corporate finance obligation ratings between AA and CCC. A BBB rating is the fourth highest of nine rating categories.

Moody's

Moody's Corporate Family Ratings (CFRs) are long-term ratings that reflect the relative likelihood of a default on a corporate family's debt and debt-like obligations and the expected financial loss suffered in the event of default. A CFR is assigned to a corporate family as if it had a single class of debt and a single consolidated legal entity structure. A CFR does not reference an obligation or class of debt and thus does not reflect priority of claim. As at December 31, 2016, our Corporate Family Rating was Ba1 with a stable outlook. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. The Ba rating category is the fifth highest

rating out of nine rating categories.

Moody's long-term ratings are assigned to issuers or obligations with an original maturity of one year or more and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default. As of December 31, 2016, our senior unsecured long-term debt is rated Ba1 (stable) / LGD4 by Moody's. The Ba rating category is the fifth highest rating out of nine rating categories. Obligations rated Ba are judged to be speculative and are subject to substantial credit risk. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Moody's Loss Given Default (LGD) assessments are opinions about expected loss given default expressed as a percent of principal and accrued interest at the resolution of the default. One of the six LGD assessments are assigned to individual loan, bond, and preferred stock issues. The firm-wide or enterprise expected LGD rate generally approximates a weighted average of the expected LGD rates on the firm's liabilities (excluding preferred stock), where the weights equal each obligation's expected share of the total liabilities at default. As of December 31, 2016, our Loss Given Default Assessment from Moody's was LGD4 which represents a loss range of greater than or equal to 50% and less than 70%. LGD4 is the fourth highest assessment category out six categories.

S&P

A Standard & Poor's issuer credit rating is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. As at December 31, 2016, our issuer credit rating was BBB- with a stable outlook with S&P. This is the fourth highest of 11 ratings categories. An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

A Standard & Poor's issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (including ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion reflects Standard & Poor's view of the obligor's capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. As at December 31, 2016, our senior unsecured rating was BBB- with a stable outlook with S&P. An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. This is the fourth highest of 11 ratings categories. The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

The Standard & Poor's Canadian preferred share rating scale serves issuers, investors, and intermediaries in the Canadian financial markets by expressing preferred share ratings (determined in accordance with global rating criteria) in terms of rating symbols that have been actively used in the Canadian market over a number of years. A Standard & Poor's preferred share rating on the Canadian scale is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific preferred share obligation issued in the Canadian market, relative to preferred shares issued by other issuers in the Canadian market. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on the global debt rating scale of Standard & Poor's. Each of our outstanding Preferred Shares Series have been rated P-3 by S&P. The P-3 rating is the third highest of eight categories. A P-3 rating corresponds to a BB rating on the global preferred share rating scale. Obligors rated 'BB', 'B', 'CCC', and 'CC' are regarded as having significant speculative characteristics, of which 'BB' indicates the least degree of speculation and 'CC' the highest. While such obligors will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. An obligor rated 'BB' is less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitments.

We are focused on maintaining a strong financial position and cash flow coverage ratios to support our business. Our available credit facilities, funds from operations, and debt financing options provide us with financial flexibility. As a result, we can be selective as to if and when we go to the capital markets for funding.

Note Regarding Credit Ratings

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

We have paid fees for rating services to S&P, DBRS, Moody's and Fitch during the last two years. We have also paid fees to S&P, DBRS, and Moody's for certain other services provided to the Corporation during the last two years.

DIVIDENDS

Common Shares

Dividends on our common shares are at the discretion of the Board. In determining the payment and level of future dividends, the Board considers our financial performance, our results of operations, cash flow and needs, with respect to financing our ongoing operations and growth, balanced against returning capital to shareholders. The Board continues to focus on building sustainable earnings and cash flow growth.

TransAlta has declared and paid the following dividends per share on its outstanding common shares for the past three years:

Period		Dividend per Common Share
2014	First Quarter	$0.29
	Second Quarter	$0.18
	Third Quarter	$0.18
	Fourth Quarter	$0.18
2015	First Quarter	$0.18
	Second Quarter	$0.18
	Third Quarter	$0.18
	Fourth Quarter	$0.18
2016	First Quarter	$0.18
	Second Quarter	$0.04
	Third Quarter	$0.04
	Fourth Quarter	$0.04
2017	First Quarter	$0.04

On December 19, 2016, the Board declared a cash dividend of $0.04 per common share, payable on April 1, 2017 to shareholders of record on March 1, 2017.

Preferred Shares

Series A Shares

Period		Dividend per Series A Share
2014	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875
2015	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875
2016	First Quarter	$0.2875
	Second Quarter	$0.16931
	Third Quarter	$0.16931
	Fourth Quarter	$0.16931

On December 19, 2016, the Board declared a cash dividend of $0.16931 per Series A Share, payable on March 31, 2017 to shareholders of record on March 1, 2017.

Series B Shares

Period		Dividend per Series B Share
2016	Second Quarter [(1)]	$0.15490
	Third Quarter	$0.16144
	Fourth Quarter	$0.15974

Note:
(1) On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares.

On December 19, 2016, the Board declared a cash dividend of $0.15651 per Series B Share, payable on March 31, 2017 to shareholders of record on March 1, 2017.

Series C Shares

Period		Dividend per Series C Share
2014	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875
2015	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875
2016	First Quarter	$0.2875
	Second Quarter	$0.2875
	Third Quarter	$0.2875
	Fourth Quarter	$0.2875

On December 19, 2016, the Board declared a cash dividend of $0.2875 per Series C Share, payable on March 31, 2017 to shareholders of record on March 1, 2017.

Series E Shares

Period		Dividend per Series E Share
2014	First Quarter	$0.3125
	Second Quarter	$0.3125
	Third Quarter	$0.3125
	Fourth Quarter	$0.3125
2015	First Quarter	$0.3125
	Second Quarter	$0.3125
	Third Quarter	$0.3125
	Fourth Quarter	$0.3125
2016	First Quarter	$0.3125
	Second Quarter	$0.3125
	Third Quarter	$0.3125
	Fourth Quarter	$0.3125

On December 19, 2016, the Board declared a cash dividend of $0.3125 per Series E Share, payable on March 31, 2017 to shareholders of record on March 1, 2017.

Series G Shares

Period		Dividend per Series G Share
2014	Fourth Quarter [(1)]	$0.501
2015	First Quarter	$0.33125
	Second Quarter	$0.33125
	Third Quarter	$0.33125
	Fourth Quarter	$0.33125
2016	First Quarter	$0.33125
	Second Quarter	$0.33125
	Third Quarter	$0.33125
	Fourth Quarter	$0.33125

Note:

(1) On October 29, 2014, the Board approved an initial dividend of $0.501 per Series G Share for the period from issuance on August 15, 2014 to December 31, 2014.

On December 19, 2016, the Board declared a cash dividend of $0.33125 per Series G Share, payable on March 31, 2017 to shareholders of record on March 1, 2017.

MARKET FOR SECURITIES

Common Shares

Our common shares are listed on the Toronto Stock Exchange (the "TSX") under the symbol "TA" and the New York Stock Exchange (the "NYSE") under the symbol "TAC". The following table sets forth the reported high and low trading prices and trading volumes of our common shares as reported by the TSX for the periods indicated:

Month	Price ($)		Volume
	High	Low	
2016			
January	4.95	3.60	29,765,528
February	6.07	4.67	25,268,680
March	6.20	5.54	30,217,831
April	6.85	5.82	21,151,921
May	7.20	6.20	25,638,554
June	7.13	6.19	17,041,471
July	6.91	6.09	13,224,097
August	6.42	5.60	11,284,388
September	6.21	5.55	16,633,890
October	6.24	5.65	10,125,084
November	7.39	5.11	24,600,911
December	7.66	7.03	14,964,416
2017			
January	8.12	7.26	12,182,667
February	7.98	7.02	14,818,463
March 1 - 2	7.14	7.00	2,089,842

Preferred Shares

Series A Shares

Our Series A Shares are listed on the TSX under the symbol "TA.PR.D".

Date(s) of Issuance	Number of Securities[2]	Issue Price per Security	Description of Transaction
December 10, 2010[1]	12,000,000 Series A Shares	$25.00	Public Offering

Note:
(1) Series A Shares were issued pursuant to a public offering by way of a prospectus supplement dated December 3, 2010 to a short form base shelf prospectus dated October 19, 2009.
(2) On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares.

Month	Price ($)		Volume
	High	Low	
2016			
January	9.90	7.02	197,292
February	8.90	7.12	329,439
March	8.99	7.98	286,692
April	9.55	8.44	284,789
May	9.89	9.30	236,821
June	9.68	9.20	166,894
July	9.58	9.27	159,769
August	9.95	9.34	337,311
September	10.13	9.35	324,420
October	10.65	9.80	178,472
November	11.90	10.37	396,123
December	13.10	11.56	858,024
2017			
January	13.24	12.13	868,789
February	13.36	13.07	1,499,985
March 1 - 2	13.23	13.07	162,597

Series B Shares

Our Series B Shares are listed on the TSX under the symbol "TA.PR.E".

Date(s) of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
March 31, 2016[1]	1,824,620 Series B Shares	N/A	Conversion of Series A Shares

Note:
(1) On March 31, 2016, 1,824,620 of the Series A Shares were converted into Series B Shares.

Month	Price ($)		Volume
	High	Low	
2016			
April	9.45	8.10	18,700
May	9.73	8.70	26,390
June	9.40	8.21	33,300
July	9.50	8.99	34,406
August	9.94	9.13	18,830
September	9.61	8.96	31,187
October	10.28	9.45	84,440
November	11.40	10.17	23,590
December	13.56	11.30	213,280
2016			
January	13.86	12.99	135,119
February	13.27	12.60	167,962
March 1 - 2	13.15	12.92	600

Series C Shares

Our Series C Shares are listed on the TSX under the symbol “TA.PR.F”.

Date(s) of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
November 30, 2011[1]	11,000,000 Series C Shares	$25.00	Public Offering

Note:
(1) Series C Shares were issued pursuant to a public offering by way of a prospectus supplement dated November 23, 2011 to a short form base shelf prospectus dated November 15, 2011.

Month	Price ($)		Volume
	High	Low	
2016			
January	12.34	8.70	178,084
February	11.40	9.05	245,057
March	12.28	10.28	290,237
April	13.04	11.50	210,630
May	12.93	11.98	184,263
June	12.26	11.10	235,431
July	11.68	11.05	163,428
August	12.18	11.31	244,810
September	12.35	11.73	266,241
October	13.54	12.15	257,680
November	14.98	13.12	348,026
December	17.26	14.80	985,032
2017			
January	17.57	16.64	483,683
February	17.39	16.55	741,081
March 1 - 2	17.04	16.88	227,365

Series E Shares

Our Series E Shares are listed on the TSX under the symbol “TA.PR.H”.

Date(s) of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
August 10, 2012[1]	9,000,000 Series E Shares	$25.00	Public Offering

Note:
(1) Series E Shares were issued pursuant to a public offering by way of a prospectus supplement dated August 3, 2012 to a short form base shelf prospectus dated November 15, 2011.

	Price ($)		
Month	High	Low	Volume
2016			
January	13.80	10.00	244,643
February	12.58	10.53	208,378
March	13.47	11.42	233,138
April	14.29	13.03	156,194
May	14.54	13.84	184,707
June	14.17	12.90	189,542
July	13.51	12.75	115,151
August	14.19	13.35	173,277
September	13.75	13.14	137,455
October	14.61	13.45	280,310
November	16.30	14.26	285,270
December	19.85	16.22	521,963
2017			
January	19.49	18.76	449,851
February	19.15	18.28	921,419
March 1 - 2	18.95	18.69	21,470

Series G Shares

Our Series G Shares are listed on the TSX under the symbol “TA.PR.J”.

Date(s) of Issuance	Number of Securities	Issue Price per Security	Description of Transaction
August 15, 2014[1]	6,600,000 Series G Shares	$25.00	Public Offering

Note:
(1) Series G Shares were issued pursuant to a public offering by way of a prospectus supplement dated August 8, 2014 to a short form base shelf prospectus dated December 9, 2013.

	Price ($)		
Month	High	Low	Volume
2016			
January	14.63	11.30	165,035
February	14.50	12.30	123,327
March	14.89	13.29	127,284
April	15.61	14.05	129,215
May	15.97	15.30	103,825
June	15.74	14.76	132,121
July	15.35	14.65	138,784
August	16.00	15.00	142,470
September	15.99	15.21	133,955
October	16.73	15.65	174,693
November	17.52	15.84	239,037
December	20.13	17.31	413,476
2017			
January	20.42	19.52	324,539
February	20.38	19.55	487,589
March 1 - 2	20.31	19.87	50,744

DIRECTORS AND OFFICERS

The name, province or state and country of residence of each of our directors as at March ·, 2017, their respective position and office and their respective principal occupation during the five preceding years, are set out below. The year in which each director was appointed to serve on the Board is also set out below. Each director is appointed to serve until the next annual meeting of TransAlta or until his or her successor is elected or appointed.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
John P. Dielwart Alberta, Canada	2014	Mr. Dielwart was formerly Chief Executive Officer of ARC Resources Ltd., which owns and operates oil and gas properties in Western Canada. He oversaw the growth of ARC Resources Ltd. from start-up in 1996 to a company with a market capitalization of approximately $10 billion. After his retirement from ARC Resources Ltd. on January 1, 2013, Mr. Dielwart re-joined ARC Financial Corp. ("ARC Financial") as Vice-Chairman. ARC Financial is Canada's leading energy-focused private equity manager. Mr. Dielwart provides leadership support for the executive team in the areas of internal governance and investment decision-making. With his extensive background in creating, building and leading one of Canada's most successful oil and gas companies, mentorship of ARC Financial employees as well as management of ARC Financial's investee companies is a primary responsibility. He is a member of ARC Financial's Investment and Strategy committees, and currently represents ARC Financial on the board of Modern Resources Ltd. and Aspenleaf Energy Limited. Prior to joining ARC Financial in 1994, Mr. Dielwart spent 12 years with a major Calgary-based oil and natural gas engineering consulting firm, as senior vice-president and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. Mr. Dielwart has a Bachelor of Science with distinction (civil engineering) degree from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and is a Past-Chairman of the Board of Governors of the Canadian Association of Petroleum Producers (CAPP). In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame. Mr. Dielwart is also the Co-Chair of the Sheldon Kennedy Child Advocacy Centre. Mr. Dielwart brings to the Company and the Board many years' experience in leadership, entrepreneurship and knowledge of the commodity markets in which we operate, specifically oil and gas markets.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation

Timothy W. Faithfull London, U.K.	2003	Mr. Faithfull is a 36 year veteran of Royal Dutch/Shell plc (energy), where he held diverse international roles principally in oil products and LNG project development. As President and Chief Executive Officer of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line in 2003, the first fully integrated oil sands mining and upgrading venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operations of Shell International Trading and Shipping Company from 1993 to 1996. He was Chairman and Chief Executive Officer of Shell Eastern Petroleum in Singapore from 1996 to 1999, including Shell's largest refinery, and its oil products trading business in Asia Pacific. In the United Kingdom, he is a director and member of the Risk and Audit Committee of ICE Futures Europe ("IFEU") and LIFFE Administration and Management, a leading global electronic exchange for energy, commodities, and financial futures. He is a member of the Oversight Committee of the ICE Brent Index, used in settlement of Brent Crude oil futures contracts, for which IFEU is the regulated benchmark administrator. He is a past director of Enerflex Systems Income Fund, Canadian Pacific Railway, AMEC plc, and Shell Pension Trust Limited. In Calgary, he served on the board of the Calgary Health Trust and the Epcor Arts Centre. In the United Kingdom, he is Chairman of the trustees of Starehe UK, which supports schools for disadvantaged children in Nairobi, Kenya, and a trustee of Canada UK Colloquium, all non-public entities. He serves on the Committee to Review Donations to the University of Oxford. Mr. Faithfull holds a Master of Arts (Philosophy, Politics and Economics) from the University of Oxford, U.K. He is a Distinguished Friend of the University of Oxford and of the London Business School. Mr. Faithfull brings to the Corporation and the Board many years of experience in leadership and, in particular, knowledge of large project development and commodity risk management in the oil and gas industry.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Dawn L. Farrell Alberta, Canada	2012	Mrs. Farrell became President and Chief Executive Officer of TransAlta Corporation on January 2, 2012. Prior to her appointment, she served as Chief Operating Officer from 2009 to 2011 and as Executive Vice-President, Commercial Operations and Development from 2008 to 2009. Mrs. Farrell has over 30 years of experience in the electric energy industry, holding roles at TransAlta and BC Hydro. She has served as Executive Vice-President, Commercial Operations and Development; Executive Vice-President, Corporate Development; Executive Vice-President, Independent Power Projects; and Vice-President, Energy Marketing and IPP Development at TransAlta Corporation. From 2003 to 2006, Mrs. Farrell served as Executive Vice-President, Generation at BC Hydro. In 2006, she was appointed Executive Vice-President Engineering, Aboriginal Relations and Generation. Mrs. Farrell sits on the board of directors of The Chemours Company, a NYSE-listed chemical company, the Conference Board of Canada, the Business Council of Canada and is a member of the Trilateral Commission. Her past boards include the Calgary Stampede, the Mount Royal College Board of Governors, Fording Coal Income Fund, New Relationship Trust Fund, Mount Royal College Foundation and Vision Quest Windelectric. Mrs. Farrell holds a Bachelor of Commerce with a major in Finance and a Master's degree in Economics from the University of Calgary. She has also attended the Advanced Management Program at Harvard University.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation

Alan J. Fohrer California, U.S.A.	2013	Mr. Fohrer was Chairman and Chief Executive Officer of Southern California Edison Company ("**SCE**"), a subsidiary of Edison International ("**Edison**") and one of the largest electric utilities in the United States. He was elected Chief Executive Officer in 2002 and Chairman in 2007. In 2000, Mr. Fohrer was elected as President and Chief Executive Officer of Edison Mission Energy ("**EME**"), a subsidiary of Edison that owns and operates independent power facilities. During his tenure at EME, Mr. Fohrer restructured a number of the international projects, which enhanced the value of the assets sold in subsequent years. Mr. Fohrer also served as Executive Vice-President, Treasurer and Chief Financial Officer of both Edison and SCE from 1995 to 1999. After 37 years with Edison, Mr. Fohrer retired in December 2010. Mr. Fohrer currently sits on the boards of PNM Resources, Inc., a publicly held energy holding company, Blue Shield of California, a non-profit health insurance provider, and Synagro, a waste management company. Mr. Fohrer has served on boards of directors of the Institute of Nuclear Power Operations, the California Chamber of Commerce, Duratek, Inc., and Osmose Utilities Services, Inc. He is also a member of the Viterbi School of Engineering Board of Councilors for the University of Southern California and Chair of the California Science Centre Foundation. Mr. Fohrer holds a Master of Science in civil engineering from the University of Southern California, Los Angeles, as well as a Master of Business Administration from California State University in Los Angeles. Mr. Fohrer brings to the Corporation and the Board experience in accounting, finance and the power industry from both a regulated and deregulated market perspective.

Name, Province (State) and Country of Residence	**Year first became Director**	**Principal Occupation**
Amb. Gordon D. Giffin Georgia, U.S.A.	2002	Ambassador Giffin is Senior Partner of the law firm of Dentons (formerly McKenna Long & Aldridge LLP), where he maintains offices in Washington, D.C. and Atlanta. His practice focuses on international transactions related to trade, energy and public policy. He has been engaged in the practice of law or government service for more than 40 years. He served as the United States Ambassador to Canada with responsibility for managing Canada/U.S. bilateral relations, including energy and environmental policy from August 1997 to April 2001. Prior to that, he served as Chief Counsel and Legislative Director to United States Senator Sam Nunn, with responsibility for the legal and legislative operations of the office. Ambassador Giffin has spent three decades as an attorney in the energy industry as an advisor, trying multiple energy regulatory cases before state and federal tribunals and courts, and handling transactions including mergers and acquisitions. During a decade in public service, he was a senior attorney and advisor in the United States Senate where, among other matters, he worked on major energy public policy initiatives. During his four years as United States Ambassador to Canada, he was Chief Executive Officer of a large government enterprise with in excess of a thousand people across Canada. His substantive responsibilities included the entire array of policy matters in the Canada-U.S. context including energy policy. He has substantial experience in dealing with issues at the intersection of industry and public policy. Since leaving public office, he resumed his continental law practice and remains actively engaged in public policy initiatives and international affairs through membership in the Council on Foreign Relations and the Trilateral Commission. Ambassador Giffin holds a Bachelor of Arts from Duke University (Durham, NC) and a Juris Doctorate from Emory University School of Law (Atlanta, GA). Ambassador Giffin brings to the Corporation and the Board experience in law, regulatory and governmental affairs that will assist the Company as it addresses continuous change in environmental law and other compliance matters.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
P. Thomas Jenkins Alberta, Canada	2014	Mr. Jenkins has been active for more than 30 years in innovation and economic development in both the private and public sectors. He is currently the Chairman of the Board of Open Text Corporation, a multinational enterprise software firm. He is also the Chancellor of the University of Waterloo. He has served as a director of Open Text Corporation since 1994 and as its Chairman since 1998. From 1994 to 2005, Mr. Jenkins was President and Chief Executive Officer, and then from 2005 to 2013, Executive Chairman and Chief Strategy Officer of Open Text Corporation. Prior thereto, he was employed in technical and managerial capacities at a variety of technology companies. Mr. Jenkins is also a director of the C.D. Howe Institute, and a director of the Business Council of Canada. Mr. Jenkins was also a member of the board of BMC Software, Inc., a software corporation based in Houston, Texas. Mr. Jenkins received a Master of Business Administration from the Schulich School of Business at York University (Toronto, ON), a Master of Applied Science from the University of Toronto and a Bachelor of Mechanical Engineering and Management from McMaster University (Hamilton, ON). Mr. Jenkins received an honorary doctorate of laws from the University of Waterloo and an honorary doctorate of Military Science from the Royal Military College of Canada. He is a recipient of the 2009 Ontario Entrepreneur of the Year, the 2010 McMaster Engineering L. W. Shemilt Distinguished Alumni Award and the Schulich School of Business 2012 Outstanding Executive Leadership award. He is a Fellow of the Canadian Academy of Engineering. Mr. Jenkins was awarded the Canadian Forces Decoration and the Queen's Diamond Jubilee Medal. Mr. Jenkins is an Officer of the Order of Canada. Mr. Jenkins brings to the Corporation and the Board several years of experience as an entrepreneur, innovator and leader in information technology which will assist the Company as it addresses both technological and innovative changes in the industry.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Yakout Mansour California, U.S.A.	2011	Mr. Mansour has over 40 years of experience as both a professional engineer and executive in the electric utility business in Canada, the United States, and abroad. He retired as President and Chief Executive Officer of the California Independent System Operator Corporation ("CAISO") in 2011, a position he had held since 2005. CAISO is responsible for operating and controlling 80% of the California electric grid, designing and operating the California electricity market, and for settlements of over $8 billion annually. Under Mr. Mansour's leadership, the California market structure was completely redesigned, and CAISO established the market and technical foundation to accommodate one of the most aggressive renewable portfolio standards in the world. Prior to that, Mr. Mansour served in senior executive roles at BC Hydro and British Columbia Transmission Corporation where he was responsible for Operation, Asset Management, and Inter-Utility Affairs of the electric grid. A Professional Engineer and a Fellow of the Institute of Electrical and Electronics Engineers, Mr. Mansour has authored and co-authored numerous publications. He is recognized internationally in the field of Power Engineering and received several distinguished awards for his contributions to the industry. In 2009, Mr. Mansour was named to the US Department of Energy Electricity Advisory Committee as a vice chair. He also served on the various committees of the North American Electric Reliability Corporation and its predecessor organization, CEGRE, the Transmission Council of the Canadian Electric Association, and the Board of Directors of the Electric Power Research Institute. Mr. Mansour holds a Bachelor of Science in electrical engineering from the University of Alexandria (Alexandria, Egypt) and a Master of Science from the University of Calgary (Calgary, AB). Mr. Mansour brings to the Corporation and the Board decades of experience in our industry i n generation, transmission and energy competitive markets in both a regulated and deregulated market environment.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Georgia Nelson Illinois, U.S.A.	2014	Ms. Nelson is President and Chief Executive Officer of PTI Resources, LLC, an independent consulting firm established in 2005. Ms. Nelson has had a 35-year career in the power generation industry, serving in various senior executive capacities for Edison International and its subsidiaries between 1971 and 2005. She was President of Midwest Generation Edison Mission Energy (EME), from 1999 to her retirement in 2005 and General Manager of EME Americas from 2002 to 2005. Her business responsibilities included management of regulated and unregulated power operations and a large energy trading subsidiary as well as the construction and operation of power generation projects in the United States, Puerto Rico, the United Kingdom, Turkey, Thailand, Indonesia, Australia and Italy. Ms. Nelson has extensive experience in international business negotiations, environmental policy matters and human resources. Ms. Nelson is currently a director of Cummins Inc., Ball Corporation, and Sims Metal Management Ltd. She is also a director of CH2MHILL Corporation, a privately held company. Ms. Nelson is a past director of Nicor, Inc. Ms. Nelson was a member of the Executive Committee of the National Coal Council from 2000-2015 and served as Chair from 2006-2008. She serves on the advisory committee of the Center for Executive Women at Northwestern University. Ms. Nelson was named to the 2012 National Association of Corporate Directors ("**NACO**") Directorship 100. She is an NACO Board Fellow. Ms. Nelson holds a Bachelor of Science form Pepperdine University and a Master of Business Administration from the University of Southern California. Ms. Nelson brings to the Corporation and the Board specialized knowledge in the energy, coal and mining industry as well as human resources management.

Name, Province (State) and Country of Residence	Year first became Director	Principal Occupation
Beverlee F. Park British Columbia, Canada	2015	Ms. Park is a senior executive with management and board experience in a range of industries, including forest products, shipping, mining, transportation, real estate, and electricity transmission. Ms. Park spent seventeen years of her career with TimberWest Forest Corp. where she was most recently Chief Operations Officer until her retirement in 2013. Over that time, she also held the roles of Interim Chief Executive Officer, President of the real estate division (Couverdon Real Estate) and Executive Vice President and Chief Financial Officer. Having provided strong leadership at the Board, Chief Executive Officer, Chief Operations Officer and Chief Financial Officer level in publicly-traded, private and Crown corporations, Ms. Park has a breadth of experience in an array of operating environments and domestic and offshore markets with specific experience leading shareholder value creation, long term strategic repositioning, operational excellence, risk management, regulatory issues, restructuring and acquisitions and divestitures. Ms. Park is currently a director of Teekay LNG Partners, a public company, where she chairs the Audit Committee. Teekay LNG Partners is one the world's largest independent owners of LNG and LPG carriers. She is also a director of Silver Standard Resources Inc., a public mining company, focused on the operation, development, exploration and acquisition of precious metals projects in North and South America. Most recently, Ms. Park was appointed to the Board of Governors at the University of British Columbia. In addition, she is a director of InTransit BC. Ms. Park was previously a director of the BC Transmission Corporation, where she chaired the Audit Committee. Ms. Park holds a Bachelor of Commerce with distinction from McGill University (Montreal, QB), a Master of Business Administration from the Simon Fraser University Executive program and is a Fellow Chartered Accountant. She is also a Fellow of the Institute of Chartered Accountants of British Columbia. Ms. Park brings to the Corporation and to the Board 30 years of experience in finance and accounting as well as leadership experience in organizational change.

Officers

The name, province or state and country of residence of each of our senior officers as at March 2, 2017, their respective position and office and their respective principal occupation are set out below.

Name	Principal Occupation	Residence
Dawn L. Farrell	President and Chief Executive Officer	Alberta, Canada
Wayne Collins	Executive Vice-President, Coal and Mining Operations	Alberta, Canada
Dawn E. de Lima	Chief Administrative Officer	Alberta, Canada
Brett M. Gellner	Chief Investment Officer	Alberta, Canada
John H. Kousinioris	Chief Legal and Compliance Officer and Corporate Secretary	Alberta, Canada
Jennifer M. Pierce	Senior Vice-President, Trading and Marketing	Alberta, Canada
Todd J. Stack	Managing Director and Corporate Controller	Alberta, Canada
Donald Tremblay	Chief Financial Officer	Alberta, Canada
Aron J. Willis	Senior Vice-President, Gas and Renewables	Alberta, Canada

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

- Prior to May 2014, Mr. Collins was Chief Operating Officer of Stanwell Corporation Limited (electrics corporation) in Australia.
- Prior to July 2015, Ms. de Lima was Chief Human Resources Officer of TransAlta. Prior to April 2012, Ms. de Lima was Chief Human Resources Officer and Executive Vice-President, Communications of TransAlta.
- Prior to August 2013, Mr. Gellner was Chief Financial Officer of the Corporation.
- Prior to October 2015, Mr. Kousinioris was Chief Legal and Compliance Officer of TransAlta. Prior to December 2012, Mr. Kousinioris was a Partner and co-head of the Corporate Commercial Group at Bennett Jones LLP, Barristers and Solicitors (law firm).
- Prior to October 2015, Ms. Pierce was Vice-President, Commercial Management of TransAlta. Prior to April 2014, Ms. Pierce was Vice-President, Commercial Management — Alberta Coal and PPAs of TransAlta.
- Prior to February 2017, Mr. Stack was Managing Director and Treasurer of TransAlta. Prior to October 2015, Mr. Stack was Vice-President and Treasurer of TransAlta. Prior to November 2012, Mr. Stack was Treasurer of TransAlta.
- Prior to March 2014, Mr. Tremblay was Executive Vice President at Brookfield Renewable Energy LP (utilities).
- Prior to January 2017, Mr. Willis was the Managing Director, Australia of TransAlta. Prior to September 2015, Mr. Willis was Vice-President, Australia of TransAlta. Prior to October 2014, he was Country Manager, Australia of TransAlta.

As of March 2, 2017, the directors and executive officers of TransAlta, as a group, beneficially owned, directly or indirectly, or exercised control or direction over less than one per cent of our outstanding common shares.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of TransAlta, no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than ten per cent of our common shares, and no associate or affiliate of any of them, has or has had any material interest, direct or indirect, in any transaction involving TransAlta within the three most recently completed financial years or to date in 2016 or in any proposed transactions that has materially affected or will materially affect us.

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2016, there has been no indebtedness outstanding to TransAlta from any of our directors, executive officers, senior officers or associates of any such directors, nominees or senior officers.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders and Bankruptcies

Except as noted below, no director, executive officer or controlling security holder of TransAlta Corporation is, as at the date of this Annual Information Form, or has been, within the past ten years before the date hereof, a director or executive officer of any other issuer that, while that

person was acting in that capacity:

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

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

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

Mr. Giffin was a director of AbitibiBowater Inc. ("Abitibi") from October 29, 2007 until his resignation on January 22, 2009. In April 2009, Abitibi and certain of its U.S. and Canadian subsidiaries filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware for relief under the provisions of Chapter 11 and Chapter 15 of the United States Bankruptcy Code, as amended, and sought creditor protection under the Companies' Creditors Arrangement Act (Canada) (the "CCAA") with the Superior Court of Québec in Canada. On September 14, 2010, Abitibi announced that it had received approval for its plan of reorganization from unsecured creditors under the CCAA in Canada. On September 21, 2010, Abitibi announced it had received the necessary creditor approval for its plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code. On December 9, 2010, Abitibi announced that it had successfully completed its reorganization and emerged from creditor protection under the CCAA in Canada and Chapter 11 of the U.S. Bankruptcy Code.

Ms. Nelson was a director of Tower International ("Tower") from 2000 to 2007. In February 2005, Tower began a voluntarily reorganization under Chapter 11 of the United States Bankruptcy Code. In July 2007, Tower completed the sale of substantially all of its assets to Tower Automotive, LLC, an affiliate of Cerberus Capital Management, L.P., and emerged from bankruptcy court protection.

Personal Bankruptcies

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

Penalties or Sanctions

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

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

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

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board serve as directors or officers of corporations which are in competition to the interests of TransAlta. No assurances can be given that opportunities identified by such member of the Board will be provided to us. However, our policies provide that each director and executive officer must comply with the disclosure requirements of the CBCA regarding any material interest. If a declaration of material interest is made, the declaring director shall not vote on the matter if put to a vote of the Board. In addition, the declaring director and executive officer may be requested to recuse himself or herself from the meeting when such matter is being discussed.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TransAlta is occasionally named as a party in claims and legal proceedings which arise during the normal course of its business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claim may not have a material adverse effect on TransAlta. For further information, please refer to **Note 32 (I)** of our audited consolidated financial statements for the year ended December 31, 2016 which financial statements are incorporated by reference herein. See "*Documents Incorporated by Reference*" in this AIF.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares and Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares is CST Trust Company. CST Trust Company succeeded CIBC Mellon Trust Company as our transfer agent. On November 1, 2010, CIBC Mellon Trust Company sold its issuer services business to Canadian Stock Transfer Company Inc. which operated the business on their behalf until August 30, 2013, at which time CST Trust Company, an affiliate of Canadian Stock Transfer Company Inc., received federal approval to commence business. Common shares are transferable in Vancouver, Calgary, Toronto, Montréal, and Halifax. Series A Shares, Series B Shares, Series C Shares, Series E Shares and Series G Shares are transferable in Calgary and Toronto. The transfer agent and registrar for our common shares in the United States is Computershare at its principal office in Jersey City, New Jersey.

INTERESTS OF EXPERTS

The Company's auditors are Ernst & Young LLP, Chartered Professional Accountants, 2200, 215 – 2 nd Street, S.W., Calgary, Alberta, T2P 1M4.

Our auditors, Ernst & Young LLP, are independent within the meaning of the Chartered Professional Accountants of Alberta Rules of Professional Conduct and have complied with the SEC's rules on auditor independence.

ADDITIONAL INFORMATION

Additional information in relation to TransAlta may be found under TransAlta's profile on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans (all where applicable), is contained

in our Management Proxy Circular for the most recent annual meeting of shareholders that involved the election of directors and can be obtained upon request from our Investor Relations department, or as filed on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Additional financial information is provided in our audited consolidated financial statements as at and for the year ended December 31, 2016 and in the related Annual MD&A, each of which is incorporated by reference in this AIF. See "*Documents Incorporated by Reference*" in this AIF.

AUDIT AND RISK COMMITTEE

General

The members of TransAlta's Audit and Risk Committee ("ARC") satisfy the requirements for independence under the provisions of Canadian Securities Regulators, National Instrument 52-110 *Audit Committees*, Section 303A of the NYSE Rules and Rule 10A-3 under the U.S. Securities and Exchange Act of 1934. The ARC's Charter requires that it be comprised of a minimum of three independent directors. The ARC is comprised of five independent members, Alan J. Fohrer (Chair), John P. Dielwart, Timothy Faithfull, Yakout Mansour, and Beverlee F. Park.

All members of the committee are financially literate pursuant to both Canadian and U.S. securities requirements and Ms. Park has been determined by the Board to be an "*audit committee financial expert*", within the meaning of Section 407 of the United States Sarbanes Oxley Act of 2002 ("Sarbanes Oxley Act").

Mandate of the Audit and Risk Committee

The ARC provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls and disclosure controls established by management of TransAlta ("Management"), iii) the risk identification and assessment process conducted by Management including the programs established by Management to respond to such risks, iv) the internal audit function, v) compliance with financial, legal and regulatory requirements and vi) the external auditors' qualifications, independence and performance. In so doing, it is the ARC's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and the Management.

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

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

The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the ARC. Designation as an "*audit committee financial expert*" does not impose on such person any duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the ARC and Board in the absence of such designation.

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

Audit and Risk Committee Charter

The Charter of the ARC is attached as Appendix "A".

Relevant Education and Experience of Audit and Risk Committee Members

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

Name of ARC Member	Relevant Education and Experience
J. P. Dielwart	Mr. Dielwart is currently the Vice-Chairman of ARC Financial Corp., an energy focused private equity manager. Mr. Dielwart served as the chief executive officer of a Canadian publicly listed company for sixteen years during which time he had extensive experience actively supervising the finance and accounting functions and public accountants. Mr. Dielwart also serves on the audit committee of Tesco Corporation, a public company.
T. W. Faithfull	Mr. Faithfull is a 36-year veteran of Royal Dutch/Shell plc (energy), where he held diverse international roles principally in oil products and LNG project development. As President and CEO of Shell Canada Limited, he was responsible for bringing the $6 billion Athabasca Oil Sands Project on line in 2003, the first fully integrated oil sands venture in 25 years. Mr. Faithfull has extensive experience with commodity exposure and risk management, the result of his time directing the global crude oil trading operations of Shell International Trading and Shipping Company from 1993 to 1996.
A. J. Fohrer	Prior to his retirement in December 2010, Mr. Fohrer was Chairman and CEO of SCE, a subsidiary of Edison and one of the largest electric utilities in the United States. Prior to that, Mr. Fohrer served as Executive Vice-President, Treasurer and Chief Financial Officer of both Edison and SCE. Mr. Fohrer also serves on the audit committee of PNM Resources Inc., a public company.
Y. Mansour	Mr. Mansour has over 40 years of experience as an executive in the electric utility business. He served as President and CEO of the CAISO and was a senior executive at BC Hydro and the British Columbia Transmission Corporation. Mr. Mansour has supervised and dealt with financial reporting and internal control.
B. Park	Ms. Park is a senior executive with management and board experience in a range of industries, including forest products, shipping, mining, transportation, real estate, and electricity transmission. Ms. Park spent seventeen years of her career with TimberWest Forest Corp. where she was most recently Chief Operations Officer. Over that time, she also held the roles of Interim Chief Executive Officer, President of the real estate division (Couverdon Real Estate) and Executive Vice President and Chief Financial Officer. Ms. Park is currently a director of Teekay LNG Partners, a public company, where she chairs the Audit Committee. Ms. Park holds a Bachelor of Commerce with distinction from McGill University (Montreal, QB), a Master of Business Administration from the Simon Fraser University Executive program and is a Chartered Accountant. She is also a Fellow of the Institute of Chartered Accountants of British Columbia.

Other Board Committees

In addition to the ARC, TransAlta has two other standing committees: the Governance and Environment Committee and the Human Resources Committee. The members of these committees as of March 2, 2017 are:

Governance and Environment Committee	Human Resources Committee
Chair: P. Thomas Jenkins	**Chair: Georgia R. Nelson**
John P. Dielwart	P. Thomas Jenkins
Timothy W. Faithfull	Beverlee F. Park
Yakout Mansour	

The Charters of the Governance and Environment Committee and the Human Resources Committee may be found on our website under Governance Board Committees at www.transalta.com. Further information about the Board and our corporate governance may also be found on our website or in our Management Proxy Circular which is filed on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

For the years ended December 31, 2016 and December 31, 2015, Ernst & Young LLP and its affiliates were paid $3,083,145 and $3,989,814 respectively, as detailed below:

Ernst & Young LLP

Year Ended December 31	2016	2015
Audit Fees	$ 2,680,186	$ 3,549,473
Audit-related fees	363,959	440,341
Tax fees	39,000	0
All other fees	0	0
Total	**$ 3,083,145**	**$ 3,989,814**

No other audit firms provided audit services in 2016 or 2015.

The nature of each category of fees is described below:

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of our annual financial statements or services provided in connection with statutory and regulatory filings or engagements, including the translation from English to French of our financial statements and other documents. Total audit fees for 2016 include payments of 1,384,384 related to 2015 and total audit fees for 2015 include payments related to 2014 in the amount of $1,607,423.

Audit-Related Fees

The audit-related fees in 2016 were primarily for work performed by Ernst & Young LLP in relation to compliance and regulatory reporting and miscellaneous accounting advice provided to the Corporation. The audit-related fees in 2015 primarily for work performed by Ernst & Young LLP in relation to compliance and regulatory reporting, debt issuances, the issuance of an economic interest in certain assets owned by the Corporation to TransAlta Renewables Inc. and miscellaneous accounting advice provided to the Corporation.

Tax Fees

The tax fees for 2016 relate to various tax related matters in our domestic and foreign operations.

All Other Fees

Nil

Pre-Approval Policies and Procedures

The ARC has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence. In May 2002, the ARC adopted a policy that prohibits TransAlta from engaging the auditors for "prohibited" categories of non-audit services and requires pre-approval of the ARC for other permissible categories of non-audit services, such categories being determined under the Sarbanes-Oxley Act of 2002. This policy also provides that the Chair of the ARC may approve permissible non-audit services during the quarter and report such approval to the ARC at its next regularly scheduled meeting.

APPENDIX "A"

AUDIT AND RISK COMMITTEE CHARTER

TRANSALTA CORPORATION
(the "Corporation")

A. Establishment of Committee and Procedures

1. Composition of Committee

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

2. Appointment of Committee Members

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

3. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and on the recommendation of the Governance and Environment Committee. The Board shall fill any vacancy if the membership of the

Committee is less than three directors.

4. Committee Chair

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

5. Absence of Committee Chair

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

6. Secretary of Committee

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

7. Meetings

The Chair of the Committee may call a regular meeting of the Committee. The Committee shall meet at least quarterly and at such other time during each year as it deems appropriate to fulfill its responsibilities. In addition, the Chair of the Committee or any two members may call a special meeting of the Committee at any time.

The Committee shall also meet in separate executive session.

8. Quorum

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

9. Notice of Meetings

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

10. Attendance at Meetings

At the invitation of the Chair of the Committee, other Board members the President and Chief Executive Officer (“CEO”), other officers or employees of the Corporation, the external auditors, and other experts or consultants may attend a meeting of the Committee.

11. Procedure, Records and Reporting

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

12. Review of Charter and Evaluation of Committee

The Committee shall evaluate its performance and review and assess the adequacy of its Charter at least annually or otherwise, as it deems appropriate. All changes proposed by the Committee are reviewed and approved by the Governance and Environment Committee and the Board.

13. Outside Experts and Advisors

The Committee Chair, on behalf of the Committee, or any of its members is authorized, at the expense of the Corporation, when deemed necessary or desirable, to retain independent counsel, outside experts and other advisors to advise the Committee independently on any matter. The retention of such counsel, expert or advisor in no way requires the Committee to act in accordance with the recommendations of such counsel, expert or advisor.

B. Duties and Responsibilities of the Chair

The fundamental responsibility of the Chair of the Committee is to effectively manage the duties of the Committee.

The Chair is responsible for:

1. Chairing meetings of the Committee and ensuring that the Committee is properly organized so that it functions effectively and meets its obligations and responsibilities.

2. Establishing the frequency of Committee meetings, duly convening the same and confirming that quorum is present when required.

3. Working with the CEO, the Chief Financial Officer (the "CFO"), the Corporate Secretary and Assistant Corporate Secretary, as applicable, on the development of agendas and related materials for the meetings.

4. Providing leadership to the Committee and assisting the Committee in ensuring the proper and timely discharge of its responsibilities.

5. Reporting to the Board on the recommendations and decisions of the Committee.

C. Mandate of the Committee

The Committee provides assistance to the Board in fulfilling its oversight responsibilities with respect to i) the integrity of the Corporation's financial statements and financial reporting process, ii) the systems of internal financial controls and disclosure controls established by Management, iii) the risk identification and assessment process conducted by Management including the programs established by Management to respond to such risks, iv) the internal audit function, v) compliance with financial, legal and regulatory requirements and vi) the external auditors' qualifications, independence and performance. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between it and the external auditors, the internal auditors and the Management of the Corporation.

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

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

The Committee must also designate at least one member as an "audit committee financial expert". The designation of a member or members as an "audit committee financial expert" is based on that individual's education and experience, which the individual will bring to bear in carrying out his or her duties on the Committee. Designation as an "*audit committee financial expert*" does not impose on such person any

duties, obligations and liability that are greater than the duties, obligations and liability imposed on another member of the Committee and Board in the absence of such designation.

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

D. Duties and Responsibilities of the Committee

1. Financial Reporting, External Auditors and Financial Planning

A) Duties and Responsibilities Related to Financial Reporting and the Audit Process

(a) Review with Management and the external auditors the Corporation's financial reporting process the work to be conducted in conjunction with the annual audit and the preparation of the financial statements, including, without limitation, the annual audit plan of the external auditors, the judgment of the external auditors as to the quality, not just the acceptability, of and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

(b) Review with Management and the external auditors the Corporation's audited annual financial statements, including the notes thereto, "Management's Discussion and Analysis", the related earnings release, and recommend their approval to the Board for release to the public;

(c) Review with Management and the external auditors the Corporation's interim financial statements, including the notes thereto, "Management's Discussion and Analysis", the related earnings release, and approve their release to the public as required;

(d) In reviewing the financial statements and related financial disclosure, the Committee shall review and discuss with Management and the external auditors:

(i) any changes in accounting principles, practices or policies considering their applicability to the business and financial impact;

(ii) Management's processes for formulating sensitive accounting estimates and the reasonableness of the estimates;

(iii) the use of "pro forma" or "non-comparable" information and the applicable reconciliation;

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

(v) disclosures made to the Committee by the CEO and CFO during their certification process for the relevant periodic/annual report filed with securities regulators to ensure that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified for the reporting period. Obtain assurances from the CEO and CFO as to the adequacy and effectiveness of the Corporation's disclosure controls and procedures and systems of internal control over financial reporting and that any fraud involving

Management or other employees who have a significant role in the Corporation's internal controls is reported to the Committee.

(e) In reviewing the financial statements and related financial disclosure, the Committee shall also, with the external auditors:

(i) discuss the cooperation they received from Management during the course of their review and their access to all records, data and information requested; and

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

(f) Review quarterly with senior Management, the Chief Legal and Compliance Officer (or, as necessary, outside legal advisors), and the Corporation's internal and external auditors, the effectiveness of the Corporation's internal controls to ensure the Corporation is in compliance with legal and regulatory requirements and the Corporation's policies;

(g) Review with Management and the external auditors the processes relating to the assessment of potential fraud, programs and controls to mitigate the risk of fraud, and the processes put in place for monitoring the risks within the targeted areas; and

(h) Discuss with Management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies.

B) Duties and Responsibilities Related to the External Auditors

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

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

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

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

(iv) review and discuss annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (a) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on their independence with the Corporation; (b) discussing with the external auditors any relationships or services that the external auditors believe may affect their objectivity and professional

skepticism; (c) reviewing with the external auditors the experience and qualifications of the senior personnel who are providing audit services to the Corporation; (d) reviewing the quality control procedures of the external auditors, including obtaining confirmation that the external auditors are in compliance with Canadian and U.S.

regulatory registration requirements; and (e) evaluating the communication and interaction with the external auditor including quality of service considerations;

(v) in the year preceding the change of the lead (or coordinating) audit partner (having primary responsibility for the audit), and in any event not less than every five years, perform a comprehensive review of the external auditor which takes into consideration (a) the impact of the tenure of the audit firm on audit quality, trends in the audit firm's performance and expertise in the industry, incidences of independence threats and the effectiveness of safeguards to mitigate those threats, (b) the responsiveness of the audit firm to changes in the entity's business and suggestions for improvement from regulators, the audit committee and/or management, (c) the consistency and rigour of the professional skepticism applied by the external auditor, and the quality of the engagement team and its communications, review of Canadian Public Accountability Board (CPAB) inspection findings since the previous comprehensive review and how the audit firm responded to these findings, and following this comprehensive review, determine whether the audit firm should be nominated to the Board as the external auditors for appointment by the shareholders at the Corporation's next general annual meeting;

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

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

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

C) Duties and Responsibilities Related to Financial Planning

(a) Review and recommend to the Board for approval the Corporation's issuance and redemption of securities (including the review of all public filings to effect any of the issuances or redemptions), financial commitments and limits, and any material changes underlying any of these commitments;

(b) Review annually the Corporation's annual tax plan;

(c) Receive regular updates with respect to the Corporation's financial obligations, loans, credit facilities, credit position and financial liquidity;

(d) Review annually with Management the Corporation's overall financing plan in support of the Corporation's capital expenditure plan and overall budget/medium range forecast; and

(e) Review with Management at least annually the approach and nature of earnings guidance and financial information to be disclosed to analysts and rating agencies.

2. Internal Audit

(a) Approve whether the internal audit function should be outsourced and if outsourced, approve the audit firm to perform such internal audit service; provided that in no event shall the external auditor be retained to also perform the internal audit function;

(b) Review and consider, as appropriate, any significant reports and recommendations made by internal audit relating to internal audit issues, together with Management's response thereto;

(c) Review annually the scope and plans for the work of the internal audit group, the adequacy of the group's resources, the internal auditors' access to the Corporation's records, property and personnel;

(d) Recognize and advise senior Management that the internal auditors shall have unfettered access to the Committee, as well as the Committee to the internal auditors;

(e) Meet separately with Management, the external auditors and internal auditors to review issues and matters of concern respecting audits and financial reporting;

(f) Review with the Corporation's senior financial Management and the internal audit group the adequacy of the Corporation's systems of internal control and procedures; and

(g) Recommend to the Human Resources Committee the appointment, termination or transfer of the lead individual responsible for internal audit, provided that if the internal audit function has been, or is being, outsourced to an audit firm, the Committee itself shall approve the appointment, termination or transfer of such audit firm.

3. Risk Management

The Board is responsible for ensuring that the Corporation has adopted processes and key policies for the identification, assessment and management of its principal risks. The Board has delegated to the Committee the responsibility for the oversight of Management's identification, and evaluation, of the Corporation's principal risks, and the implementation of appropriate policies, processes and systems to manage or mitigate the risks within the Corporation's risk appetite. The Committee reports to the Board thereon.

The Committee shall:

(a) Review, at least quarterly, Management's assessment of the Corporation's principal risks; discuss with Management the processes for the identification of these risks and the efficacy of the policies and procedures for mitigating and/or addressing these risks;

(b) Receive and review Managements' quarterly risk update including an update on residual risks;

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

(d) Review annually the Corporation's Financial and Commodity Exposure Management Policies and approve changes to such policies;

(e) Review and approve the Corporation's strategic hedging program, guidelines and risk tolerance;

(f) Review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;

(g) Review the Corporation's annual insurance program, including the risk retention philosophy, potential exposure and corporate liability protection programs;

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

(i) Annually, together with Management, report and review with the Board:

(i) the Corporation's principal risks and overall risk appetite/profile;

(ii) the Corporation's strategies in addressing its risk profile;

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

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

4. Governance

A) Public Disclosure, Legal and Regulatory Reporting

(a) On behalf of the Committee, the Chair shall review all public disclosure inclusive of material financial information extracted or derived from the Corporation's financial statements prior to dissemination to the public;

(b) Review quarterly with the Chief Legal and Compliance Officer, and, if necessary, outside legal advisors, significant legal, compliance or regulatory matters that may have a material effect on the Corporation's financial statements;

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

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

(e) Review annually the Insider Trading Policy and approve changes as required; and

(f) Review annually the Corporation's Disclosure Policy and Social Media Policy to ensure continued applicability with the law and the Corporation's disclosure principles.

B) Pension Plan Governance

(a) Review annually the Annual Pension Report and financial statements of the Corporation's pension plans including the actuarial valuation, asset/liability forecast, asset allocation, manager performance and plan operating costs and reporting thereon to the Board annually; and

(b) Together with the Human Resources Committee of the Board, review annually, and as required, the overall governance of the Corporation's Pension Plans, approving the broad objectives of the plans, the statement of investment policy, the appointment of investment managers, and reporting thereon to the Board annually.

C) Information Technology – Cyber Security

(a) Receive bi-annually a system status update with respect to the Corporation's core IT operating systems; and

(b) Review annually the Corporation's cyber security programs and their effectiveness. Receive an update on the Corporation's compliance program for cyber threats and security.

D) Administrative Responsibilities

(a) Review the annual audit of expense accounts and perquisites of the Directors, the CEO and her direct reports and their use of Corporate assets;

(b) Establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal and disclosure controls or auditing matters and the confidential, anonymous submission by employees, contractors, shareholders and other stakeholders of concerns regarding accounting, auditing, ethical or legal violations;

(c) Review all incidents, complaints or information reported through the Ethics Help Line and/or Management;

(d) Initiate investigations of complaints or allegations as necessary, report to the Board thereon and ensure that appropriate action is taken as necessary to address the matter;

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

(f) Report annually to shareholders on the work of the Committee during the year.

E. Compliance and Powers of the Committee

(a) The responsibilities of the Committee comply with applicable Canadian laws and regulations, such as the rules of the Canadian Securities Administrators, and with the disclosure and listing requirements of the Toronto Stock Exchange, as they exist on the date hereof. In addition, this Charter complies with applicable U.S. laws, such as the Sarbanes-Oxley Act and the rules and regulations adopted thereunder, and with the New York Stock Exchanges' corporate governance standards, as they exist on the date hereof.

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

APPENDIX "B"

GLOSSARY OF TERMS

This Annual Information Form includes the following defined terms:

Air Emissions – Substances released to the atmosphere through industrial operations. For the fossil-fuel-fired power sector, the most common air emissions are sulphur dioxide, oxides of nitrogen, mercury, and greenhouse gases.

Power Purchase Arrangement (PPA) – A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

Availability – A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Balancing Pool – The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the *Electric Utilities Act* (effective June 1, 2003) and the *Balancing Pool Regulation*. For more information go to www.balancing pool.ca

Boiler – A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Capacity – The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Cogeneration – A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Combined-Cycle – An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Dividend – Refers to a cash dividend declared payable by the Board of Directors of TransAlta on the outstanding Shares.

eERP – ecoEnergy for Renewable Power program, a program established by the Federal Government.

Force Majeure – Literally means “greater force”. These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Gigawatt – A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh) – A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG) – Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

LTC – Long term contract.

Megawatt (MW) – A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) – A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Net Capacity – The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Supercritical Conbustion – The most advanced coal-combustion technology in Canada employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Uprate – To increase the rated electrical capability of a power generating facility or unit.

TRANSALTA CORPORATION

Management's Discussion and Analysis

Table of Contents

Forward-Looking Statements	M2	Financial Instruments	M58
Additional IFRS Measure and Non-IFRS Measures	M3	2017 Financial Outlook	M60
Business Model	M4	Governance and Risk Management	M64
Highlights	M5	Critical Accounting Policies and Estimates	M75
Reconciliation of Non-IFRS Measures	M8	Accounting Changes	M82
Comparable Results	M12	Fourth Quarter	M84
Competitive Forces	M26	Reconciliation of Non-IFRS Measures	M86
TransAlta's Capitals	M28	Selected Quarterly Information	M90
Other Consolidated Analysis	M50	Disclosure Controls and Procedures	M91

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2016 consolidated financial statements and our Annual Information Form for the year ended Dec. 31, 2016. Our consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Dec. 31, 2016. All dollar amounts in the following discussion, including the tables, are in millions of Canadian dollars unless otherwise noted and except amounts per share which are in whole dollars to the nearest two decimals. This MD&A is dated March 2, 2017. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us", or the "Corporation"), including our Annual Information Form, is available on SEDAR at ***www.sedar.com****, on EDGAR at* ***www.sec.gov****, and on our website at* ***www.transalta.com****. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A, the documents incorporated herein by reference, and other reports and filings made with securities regulatory authorities include forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements, including the 2017 Financial Outlook section and Sustainable Development Targets section of this MD&A, are presented for general information purposes only and not as specific investment advice. All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions, and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "project", "forecast", "foresee", "potential", "enable", "continue", or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties, and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward-looking statements pertaining to our business and anticipated future financial performance; our success in executing on our growth projects; the timing of the construction and commissioning of projects under development, including major projects such as the South Hedland power project and the Sundance 7 project, and their attendant costs; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; expected decommissioning costs; the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses, expectations relating to the dispositions of assets and the completion of sale transactions including the disposition of our interest in the Wintering Hills wind facility; expectations related

to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2017 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), comparable free cash flow ("FCF"), and expected sustaining capital expenditures); expectations in respect of financial ratios and targets and the timing associated with meeting such targets (including comparable FFO before interest to adjusted interest coverage, adjusted comparable FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); the Corporation's plans and strategies relating to repositioning its capital structure and strengthening its balance sheet and the debt reductions that are expected to occur in 2017 and beyond; expected governmental regulatory regimes and legislation (including the Government of Alberta's Climate Leadership Plan) and proposed regulations to discontinue over time the use of technologies that our coal-fired plants currently utilize, and their expected impact on TransAlta and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected results and impact of the recently signed Off-Coal Agreement ("OCA") and Memorandum of Understanding ("MOU") with the Government of Alberta on our business and financial performance; the outcome of discussions with the Government of Alberta in relation to potential opportunities for investment in renewable and gas-fired generation; our comparative advantages over our competitors; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term, and the resulting impact on electricity prices; our share of offer control in the Province of Alberta after the expiry of the Power Purchase Arrangements ("PPAs") at the end of 2020; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs, including the impact of the anticipated elimination of current excess system capacity and future growth in Alberta driven by the retirement of coal units over the next 15 years; expected financing of our capital expenditures; the anticipated financial impact of increased carbon price (including under the existing Specified Gas Emitters Regulation) ("SGER") in Alberta; expectations in respect of our environmental initiatives; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar, the Australian dollar, and other currencies in which we do business; the monitoring of our exposure to liquidity risk; expectations regarding the impact of the slowdown in the oil and gas sector; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; expected cost savings following the implementation of our efficiency and productivity initiatives; the estimated contribution of Energy Marketing activities to gross margin;

expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of TransAlta Renewables; the refinancing our upcoming debt maturities over the next two years by raising $700 million to $900 million of debt secured by contracted cash flows; expectations regarding our de-leveraging strategy, including applying a portion of our free cash flow over the next four years to reduce debt expectations in respect of our community initiatives; impacts of future IFRS standards; and amendments or interpretations by accounting standard setters prior to initial adoption of those standards.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and the availability of fuel supplies required to generate electricity; our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural or man-made disasters; the threat of terrorism and cyberattacks and our ability to manage such attacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing and the ability to access financing at a reasonable cost; our ability to fund our growth projects; our ability to maintain our investment grade credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays or changes in costs in the construction of the South Hedland power project; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and under the heading "Risk Factors" in our 2017 Annual Information Form.

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

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2016, 2015, and 2014. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of the financial measures discussed in this MD&A are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. See the Comparable Funds from Operations and Comparable Free Cash Flow, Discussion of Segmented Comparable Results, and Earnings on a Comparable Basis sections of this MD&A for additional information.

Business Model

Our Business
We are one of Canada's largest publicly traded power generators with over 105 years of operating experience. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets representing nearly 9,000 MW[1] of net generating capacity and use a broad range of generation fuels that include coal, natural gas, water, sun, and wind. We are Canada's largest generator of wind power and the largest generator of renewable energy in Alberta. Our energy marketing operations maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions.

Vision and Values
Our vision is to be a leading clean energy company, using our expertise, scale, and diversified fuel mix to capitalize on opportunities in our core markets and growing in areas where our competitive advantages can be employed. Our values are grounded in accountability, integrity, safety, respect for people, innovation and loyalty which together create a strong corporate culture and allow all of our people to work on a common ground and understanding. These values are at the heart of our success.

Strategy for Value Creation
Our goals are to deliver solid returns by developing and operating assets in our three regions and among five fuel types. By 2030, our fleet will be fully transitioned from coal to natural gas and renewables. We maximize value by contracting assets, achieving strong availability, and aiming for first-quartile costs. Our Energy Marketing group adds value to merchant assets through optimization. We develop new greenfield projects and undertake merger and acquisition activities to ensure strategic growth of cash flows over the long term. The transition from coal to natural gas and renewables provides significant opportunity for future growth. In 2013, we launched TransAlta Renewables, our sponsored vehicle to own contracted gas and renewable assets.

(1) We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated, and reflect the basis of consolidation of underlying assets.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	**2016**	2015	2014
Revenues	**2,397**	2,267	2,623
Comparable EBITDA[1]	**1,145**	945	1,036
Net earnings (loss) attributable to common shareholders	**117**	(24)	141
Comparable net earnings (loss) attributable to common shareholders[1]	**34**	(48)	68
Comparable FFO[1]	**763**	740	762
Cash flow from operating activities	**744**	432	796
Comparable FCF[1]	**299**	315	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.41**	(0.09)	0.52
Comparable net earnings (loss) per share[1]	**0.12**	(0.17)	0.25
Comparable FFO per share[1]	**2.65**	2.64	2.79
Comparable FCF per share[1]	**1.04**	1.13	1.03
Dividends declared per common share	**0.20**	0.72	0.72

As at Dec. 31	**2016**	2015	2014
Total assets	**10,996**	10,947	9,833
Total debt[2]	**4,056**	4,441	4,013

Total long-term liabilities	**5,116**	5,704	4,504

In 2016, comparable EBITDA increased by $200 million to $1,145 million compared to 2015, with all segments other than U.S. Coal delivering improved results over last year. The improved results throughout the year are a result of positive contributions from renewable assets acquired in the second half of 2015, solid performance from our gas and renewables portfolios, cost reduction initiatives across the fleet implemented in 2015, and the reversal of the $80 million provision relating to our Keephills 1 outage in 2013. Our highly contracted profile and hedging strategy mitigated the impact of lower prices during the year. The decreased contribution from U.S. Coal is attributable to unfavourable market conditions in the Pacific Northwest. Last year's comparable EBITDA was impacted by a $59 million increase in our provision relating to the Keephills 1 outage in 2013.

Comparable FFO increased by $23 million to $763 million. The increase was lower than the increase in comparable EBITDA, primarily due to the non-cash impact of the provision relating to our Keephills 1 outage, which was approximately $139 million of the change in comparable EBITDA.

Reported net earnings attributable to common shareholders was $117 million ($0.41 net earnings per share) compared to a net loss of $24 million ($0.09 net loss per share) in 2015. Comparable net earnings attributable to common shareholders was $34 million ($0.12) net earnings per share), up from a comparable net loss of $48 million ($0.17 net loss per share) in 2015. The improvements year-over-year primarily relate to contributions from assets we acquired in 2015, solid performance from the renewable asset portfolio, and cost reduction initiatives. The Keephills 1 outage provision reversal also favourably impacted 2016 net earnings. Our reported net earnings attributable to common shareholders in 2016 was impacted positively by the Mississauga cogeneration recontracting ($48 million[3]) and negatively by the Wintering Hills wind facility impairment ($21 million[3]). Changes in the fair value of de-designated and economic hedges at U.S. Coal also had a negative impact on our reported net earnings of $17 million[3,4] in 2016 (2015 – $38 million[3,4]).

(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow and Earnings on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) Total debt includes current portion, amounts due under credit facilities, long-term debt, tax equity, and finance lease obligations net of cash.

(3) Net of related income tax expense.

(4) Hedge accounting could not be applied to certain contracts, and accordingly, the mark-to-market on these contracts impacted reported earnings. The impacts of these mark-to-market fluctuations have been removed from revenues to arrive at comparable results, which reflect the economic nature of these contracts.

2015's reported net loss also included the gain on the Poplar Creek restructuring ($192 million[1]), the cost of the settlement with the Market Surveillance Administrator (the "MSA") ($55 million[1]), and a $95 million income tax expense related to an internal reorganization. These items are not included in our comparable net earnings.

The decrease of $385 million in total debt, net of cash, is primarily due to repayment of debt using the proceeds received from the sale to TransAlta Renewables of economic interests in the Canadian Assets (as defined below) completed in January 2016, free cash flows generated by the business, and the strengthening of the Canadian dollar.

Significant Events

At the beginning of the year we had three strategic objectives: first, work with the Government of Alberta to develop a plan that would facilitate our transition from coal to natural gas and renewables; second, continue to improve our financial condition and flexibility by reducing our total outstanding corporate debt and better aligning our debt maturities with the life of our assets; and third, commit ourselves to achieving our operational goals (health and safety, equipment availability, and environment). We made significant progress on our strategic objectives in 2016. Our results for the year demonstrate our financial and operating stability. Specifically, we:

- Entered into an OCA with the Government of Alberta (the "Government") for the cessation of coal-fired emissions at our Alberta coal facilities. Under the terms of the OCA, we will receive transition payments of approximately $37.4 million (our net share) from 2017 to 2030 for a total amount of approximately $524 million.
- Entered into an MOU with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market.
- Signed a new contract for our Mississauga cogeneration facility effective Jan. 1, 2017, with Ontario's Independent Electricity System Operator ("IESO") and terminated our existing contract early. The new contract, which expires in December 2018, provides us with monthly payments totalling approximately $209 million over the term of the contract with no delivery obligations. The new contract will allow us to reduce operational costs for this facility while retaining flexibility to operate the facility should economic conditions permit.
- Completed the sale to TransAlta Renewables of an economic interest in the Sarnia cogeneration facility and two renewable energy facilities (collectively, the "Canadian Assets") for aggregate proceeds valued at $540 million. Cash proceeds of this transaction were $173 million. We also received 15.6 million common shares of TransAlta Renewables and a $215 million convertible debenture. Proceeds were used to reduce TransAlta's indebtedness. In November 2016, the economic interest was converted to direct ownership of the Canadian Assets by TransAlta Renewables.
- Repositioned our capital structure through two non-recourse bond issuances in 2016, through our subsidiaries, New Richmond Wind L.P. and TAPC Holdings L.P., in the amounts of $159 million and $202.5 million, respectively. These financings have aligned debt maturities with the contracted cash flows of the underlying assets.
- Announced the sale of our 51 per cent interest in the 88 MW Wintering Hills merchant wind facility, located in Alberta, for approximately $61 million in early 2017. The sale provides us with near-term liquidity, increases our financial flexibility, and reduces our merchant exposure in Alberta.
- Continued to advance the construction of the South Hedland power project. We expect the project to be delivered on schedule and on budget in mid-2017.
- Announced a reduction of our dividend to $0.16 per common share on an annualized basis from $0.72 previously. As a result, our annual dividend is approximately $46 million, down from $205 million, thereby increasing our financial flexibility.

These actions, coupled with our solid financial performance in 2016, are expected to build the financial capacity and flexibility to address upcoming debt maturities and capitalize on growth opportunities in gas-fired and renewable generation that are expected to arise as Alberta transitions from its reliance on coal-fired generation to cleaner sources of power generation.

(1) Net of related income tax expense.

Reconciliation of Non-IFRS Measures

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

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO is an important metric as it provides a proxy for the amount of cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FCF is an important metric as it represents the amount of cash generated by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort comparable FFO and comparable FCF with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects. Comparable FFO per share and comparable FCF per share are calculated using the weighted average number of common shares outstanding during the period.

The table below reconciles our cash flow from operating activities to our comparable FFO.

Year ended Dec. 31	**2016**	2015	2014
Cash flow from operating activities	**744**	432	796
Change in non-cash operating working capital balances	**(73)**	242	(73)
Cash flow from operations before changes in working capital	**671**	674	723
Adjustments			
MSA settlement payment and California claim	**25**	31	33
Decrease in finance lease receivable	**57**	23	3
Restructuring costs	**4**	19	-
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	**-**	(9)	1
Other	**6**	2	2
Comparable FFO	**763**	740	762
Deduct:			
Sustaining capital	**(272)**	(305)	(361)
Insurance recoveries of sustaining capital expenditures	**1**	25	4
Dividends paid on preferred shares	**(42)**	(46)	(41)
Distributions paid to subsidiaries' non-controlling interests	**(151)**	(99)	(84)
Comparable FCF	**299**	315	280
Weighted average number of common shares outstanding in the year	**288**	280	273
Comparable FFO per share	**2.65**	2.64	2.79
Comparable FCF per share	**1.04**	1.13	1.03

Reconciliation of Comparable EBITDA and Comparable Net Earnings

Comparable EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. Interest, taxes, and depreciation and amortization are not included, as differences in accounting, treatments may distort our core business results. A reconciliation of reported results to comparable results for the year ended Dec. 31, 2016, is as follows:

Year ended Dec. 31	**2016**			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**
Revenues	**2,397**	**123** (1, 2)	**26** (5)	**2,546**
Fuel and purchased power	**963**	**(65)** (3)	**(14)** (9)	**884**
Gross margin	**1,434**	**188**	**40**	**1,662**
Operations, maintenance, and administration	**489**	**-**	**-**	**489**
Asset impairment	**28**	**-**	**(28)** (8)	**-**
Restructuring	**1**	**-**	**(1)** (10)	**-**
Taxes, other than income taxes	**31**	**-**	**-**	**31**

Net other operating (income) losses	**(194)**	**-**	**191** (9)	**(3)**
EBITDA	**1,079**	**188**	**(122)**	**1,145**
Depreciation and amortization	**601**	**122** (2, 3, 4)	**(46)** (9)	**677**
Operating income	**478**	**66**	**(76)**	**468**
Finance lease income	**66**	**(66)** (1)	**-**	**-**
Foreign exchange loss	**(5)**	**-**	**(3)** (17)	**(8)**
Gain on sale of assets	**4**	**-**	**(4)** (15)	**-**
Earnings (loss) before interest and taxes	**543**	**-**	**(83)**	**460**
Net interest expense	**229**	**-**	**-**	**229**
Income tax expense	**38**	**-**	**4** (18, 19, 20, 21)	**42**
Net earnings	**276**	**-**	**(87)**	**189**
Non-controlling interests	**107**	**-**	**(4)** (23)	**103**
Net earnings (loss) attributable to TransAlta shareholders	**169**	**-**	**(83)**	**86**
Preferred share dividends	**52**	**-**	**-**	**52**
Net earnings (loss) attributable to common shareholders	**117**	**-**	**(83)**	**34**
Weighted average number of common shares outstanding in the year	**288**			**288**
Net earnings (loss) per share attributable to common shareholders	**0.41**			**0.12**

A reconciliation of reported results to comparable results for the year ended Dec. 31, 2015, is as follows:

Year ended Dec. 31	2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,267	81 (1, 2)	60 (5)	2,408
Fuel and purchased power	1,008	(62) (3)	-	946
Gross margin	1,259	143	60	1,462
Operations, maintenance, and administration	492	-	9 (6)	501
Asset impairment reversals	(2)	-	2 (8)	-
Restructuring	22	-	(22) (10)	-
Taxes, other than income taxes	29	-	-	29
Net other operating (income) losses	25	-	(38) (7, 11)	(13)
EBITDA	693	143	109	945
Depreciation and amortization	545	85 (2, 3, 4)	-	630
Operating income	148	58	109	315
Finance lease income	58	(58) (1)	-	-
Foreign exchange gain	4	-	8 (17)	12
Gain on sale of assets	262	-	(262) (12)	-
Earnings (loss) before interest and taxes	472	-	(145)	327
Net interest expense	251	-	-	251
Income tax expense	105	-	(107) (18,19,20,21)	(2)
Net earnings	116	-	(38)	78
Non-controlling interests	94	-	(14) (23)	80
Net earnings (loss) attributable to TransAlta shareholders	22	-	(24)	(2)
Preferred share dividends	46	-	-	46
Net earnings (loss) attributable to common shareholders	(24)	-	(24)	(48)
Weighted average number of common shares outstanding in the year	280			280
Net loss per share attributable to common shareholders	(0.09)			(0.17)

A reconciliation of reported results to comparable results for the year ended Dec. 31, 2014, is as follows:

Year ended Dec. 31	2014			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total

Revenues	2,623	52 (1, 2)	(54) (5)	2,621
Fuel and purchased power	1,092	(56) (3)	-	1,036
Gross margin	1,531	108	(54)	1,585
Operations, maintenance, and administration	542	-	(6) (6, 13)	536
Asset impairment reversal	(6)	-	6 (8)	-
Taxes, other than income taxes	29	-	-	29
Gain on sale of assets	-	(1) (4)	-	(1)
Net other operating (income) losses	(14)	-	(1) (7, 14)	(15)
EBITDA	980	109	(53)	1,036
Depreciation and amortization	538	60 (2, 3, 4)	-	598
Operating income	442	49	(53)	438
Finance lease income	49	(49) (1)	-	-
Foreign exchange gain	-	-	4 (16)	4
Gain on sale of assets	2	-	(2) (15)	-
Earnings before interest and taxes	493	-	(51)	442
Net interest expense	254	-	-	254
Income tax expense	7	-	23 (18, 20, 22)	30
Net earnings	232	-	(74)	158
Non-controlling interests	50	-	(1) (23)	49
Net earnings attributable to TransAlta shareholders	182	-	(73)	109
Preferred share dividends	41	-	-	41
Net earnings (loss) attributable to common shareholders	141	-	(73)	68
Weighted average number of common shares outstanding in the year	273			273
Net earnings per share attributable to common shareholders	0.52			0.25

The adjustments made to calculate comparable earnings for the years ended Dec. 31, 2016, 2015 and 2014 are as follows. References are to the previous reconciliation tables.

Year ended Dec. 31				**2016**	2015	2014
Reference number	**Adjustment**	**Segment**	**Financial Statement line item**			
Reclassifications:						
1	Finance lease income used as a proxy for operating revenue	Australian Gas	Revenues	**52**	49	42
		Canadian Gas	Revenues	**14**	9	7
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	Revenues	**54**	23	4
		Australian Gas	Revenues	**3**	-	(1)
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	Fuel and purchased power	**65**	62	56
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Canadian Coal	Gain on sale of assets	**-**	-	1
Adjustments (increasing (decreasing) earnings to arrive at comparable results):						
5	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	Revenues	**26**	60	(54)
6	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	OM&A	**-**	(9)	1
7	Non-comparable portion of insurance recovery received	Hydro	Net other operating (income) losses	**-**	(18)	(4)
8	Asset impairment charges (reversals)	U.S. Coal	Asset impairment (reversals)	**-**	(2)	(5)
		Canadian Gas	Asset impairment (reversals)	**-**	-	(1)
		Wind and Solar	Asset impairment (reversals)	**28**	-	-
9	Mississauga recontracting[1]	Canadian Gas	Net other operating (income) losses	**(131)**	-	-
10	Restructuring expense	Canadian Coal	Restructuring	**-**	11	-
		U.S. Coal	Restructuring	**-**	1	-
		Canadian Gas	Restructuring	**-**	1	-
		Hydro	Restructuring	**-**	-	-
		Energy Marketing	Restructuring	**-**	3	-

		Corporate	Restructuring	**1**	6	-
11	MSA settlement	Energy Marketing	Net other operating (income) losses	**-**	56	-
12	Gain on Poplar Creek contract restructuring	Canadian Gas	Gain on sale of assets	**-**	(262)	-
13	Costs related to TAMA Transmission bid	Corporate	OM&A	**-**	-	5
14	California claim	Energy Marketing	Net other operating (income) losses	**-**	-	5
15	Non-comparable gain on sale of assets	Equity Investments	Gain on sale of assets	**-**	-	(2)
		Corporate	Gain on sale of assets	**(4)**	-	-
16	Foreign exchange on California claim	Unassigned	Foreign exchange gain (loss)	**-**	-	4
17	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	Foreign exchange gain (loss)	**(3)**	8	-
18	Net tax effect on comparable adjustments subject to tax	Unassigned	Income tax expense (recovery)	**2**	48	18
19	Deferred income tax rate adjustment	Unassigned	Income tax expense (recovery)	**1**	20	-
20	Reversal of writedown of deferred income tax assets	Unassigned	Income tax expense (recovery)	**(10)**	(56)	(5)
21	Income tax expense related to temporary difference on investment in subsidiary	Unassigned	Income tax expense (recovery)	**3**	95	-
22	Income tax recovery related to sale of investment	Unassigned	Income tax expense (recovery)	**-**	-	(36)
23	Non-comparable items attributable to non-controlling interest	Unassigned	Non-controlling interests	**4**	14	1

(1) Reported in net other operating (income) loss of ($191 million), depreciation and amortization of ($46 million), and fuel and purchased power of ($14 million).

Comparable Results

Discussion of Comparable FFO and Comparable FCF

The table below provides a reconciliation of our comparable EBITDA to our comparable FFO and comparable FCF.

Year ended Dec. 31	**2016**	2015	2014
Comparable EBITDA	**1,145**	945	1,036
Provisions	**(85)**	73	-
Unrealized losses from risk management activities	**3**	1	4
Interest expense	**(219)**	(230)	(236)
Current income tax expense	**(23)**	(19)	(33)
Realized foreign exchange gain	**1**	17	11
Decommissioning and restoration costs settled	**(23)**	(24)	(16)
Gain on curtailment and amendment of employee future benefit plans	**-**	(8)	-
Capital insurance recoveries	**(1)**	(7)	-
Other non-cash items	**(35)**	(8)	(4)
Comparable FFO	**763**	740	762
Deduct:			
Sustaining capital	**(272)**	(305)	(361)
Insurance recoveries of sustaining capital expenditures	**1**	25	4
Dividends paid on preferred shares	**(42)**	(46)	(41)
Distributions paid to subsidiaries' non-controlling interests	**(151)**	(99)	(84)
Comparable FCF	**299**	315	280

Comparable FFO was $763 million for 2016 as compared to $740 million for 2015. The full year contribution from renewable assets we acquired in late 2015 added $25 million to our comparable EBITDA and comparable FFO. Operations, maintenance, and administration ("OM&A") cost reduction initiatives across the fleet also increased comparable EBITDA and comparable FFO. Lower prices in Alberta and the Pacific Northwest negatively impacted our business, but the impact was mitigated by the high level of contracts and hedges in each market.

For the year ended Dec. 31, 2015, comparable FFO decreased by $22 million to $740 million compared to 2014, mainly due to the higher outages and derates in Alberta, and lower prices in Alberta and the Pacific Northwest.

Comparable FCF for 2016 was down by $16 million, largely related to higher distributions paid to subsidiaries' non-controlling interests. Higher comparable FCF in 2015 compared to 2014 was mostly due to lower sustaining capital expenditures as a result of reductions in mining expenditures, deferral of major work in Centralia as a result of economic dispatching, and reductions in our gas-fired capital expenditures caused by the Poplar Creek recontracting.

Discussion of Segmented Comparable Results

In 2016, we disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas.

Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Each business segment assumes responsibility for its operating results measured to comparable EBITDA. Operating income and gross margin are also useful measures as they provide management and investors with a measurement of operating performance that is readily comparable from period to period.

Canadian Coal

Year ended Dec. 31	**2016**	2015	2014
Availability (%)	**85.3**	84.3	88.6
Contract production (GWh)	**19,823**	20,256	21,748
Merchant production (GWh)	**3,787**	3,827	3,806
Total production (GWh)	**23,610**	24,083	25,554
Gross installed capacity (MW)	**3,791**	3,786	3,771
Revenues	**1,048**	912	1,023
Fuel and purchased power	**386**	379	436
Comparable gross margin	**662**	533	587
Operations, maintenance, and administration	**178**	194	196
Taxes, other than income taxes	**13**	12	12
Gain on sale of assets	**-**	**-**	(1)
Net other operating income	**(2)**	(7)	(9)
Comparable EBITDA	**473**	334	389
Depreciation and amortization	**307**	299	292
Comparable operating income	**166**	35	97
Sustaining capital:			
Routine capital	**33**	48	56
Mine capital	**23**	25	45
Finance leases	**13**	10	10
Planned major maintenance	**100**	107	100
Total sustaining capital expenditures	**169**	190	211
Insurance recoveries of sustaining capital expenditures	**-**	(7)	-
Net amount	**169**	183	211

2016

Production for the year ended Dec. 31, 2016, decreased 473 gigawatt hours ("GWh") compared to 2015, primarily due to higher paid curtailments in the first half of the year and higher levels of economic dispatching, in both cases caused by lower prices in Alberta. This was partially offset by lower planned outages and derates. Unplanned outages remained at a similar level compared to last year.

Comparable EBITDA for the year ended Dec. 31, 2016, increased $139 million compared to 2015, primarily due to the reversal of the $80 million provision relating to the Keephills 1 outage in 2013. The year-over-year impact to comparable EBITDA of this provision was $139 million, as last year's comparable EBITDA was reduced by $59 million due to this provision. Our high level of contracted generation and hedging strategy largely mitigated the impact of low power prices in Alberta. Comparable EBITDA was also positively impacted by a reduction in our operations, maintenance, and administration costs.

For the year ended Dec. 31, 2016, sustaining capital expenditures decreased by $21 million compared to 2015, mainly due to lower expenditures on our turnaround outages executed on two of our operated units and deferral of discretionary projects into 2017.

2015

Production for the year ended Dec. 31, 2015, decreased 1,471 GWh compared to 2014, primarily due to unplanned outages in the first half of 2015 (Sundance 4 and the Keephills 1 outage) and derates due to high temperatures impacting cooling ponds in the spring and summer months. The planned outage at Sundance 3 was extended as a result of the level of turbine work required. Generation was also reduced due to economic dispatching resulting from the low price environment in 2015.

In 2015, comparable EBITDA included a $59 million adjustment to provisions primarily in relation to prior year events. Excluding the adjustment to provisions, comparable EBITDA would have been $393 million in 2015, in line with 2014. Reductions in operating expenses at our Highvale mine and mark-to-market gains on certain forward financial contracts that do not qualify for hedge accounting fully offset the negative impact of year-over-year lower availability on our comparable EBITDA. Our high level of contracts and hedges in Canadian Coal mostly offset the impact of lower prices in Alberta compared to 2014. Other

operating income in 2015 represents insurance recoveries received in connection with the Keephills 1 force majeure outage and additional work at Sundance 3.

For the year ended Dec. 31, 2015, sustaining capital expenditures decreased by $21 million compared to 2014. In 2014, we incurred additional costs for the development of a new mining area, and the acquisition and refurbishment of vehicles as part of our mining operations.

U.S. Coal

Year ended Dec. 31	**2016**	2015[2]	2014[2]
Availability (%)	**88.1**	87.4	82.8
Adjusted availability (%)[1]	**88.9**	89.5	87.7
Contract sales volume (GWh)	**3,535**	2,868	1,131
Merchant sales volume (GWh)	**4,896**	5,484	6,102
Purchased power (GWh)	**(3,854)**	(3,329)	(549)
Total production (GWh)	**4,577**	5,023	6,684
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues	**380**	432	369
Fuel and purchased power	**281**	316	255
Comparable gross margin	**99**	116	114
Operations, maintenance, and administration	**54**	50	49
Taxes, other than income taxes	**4**	3	3
Comparable EBITDA	**41**	63	62
Depreciation and amortization	**61**	63	54
Comparable operating income (loss)	**(20)**	-	8
Sustaining capital:			
Routine capital	**3**	2	2
Finance leases	**3**	3	-
Planned major maintenance	**11**	10	10
Total	**17**	15	12

2016

Production was down 446 GWh in 2016 compared to 2015, due mainly to increased economic dispatching in the first half of the year caused by lower prices. We supplied our contractual obligations by buying less expensive power in the market during such periods.

Comparable EBITDA decreased by $22 million compared to 2015 as a result of reduced margins due to lower prices and the unfavourable impact of mark-to-market on certain forward financial contracts that do not qualify for hedge accounting. This was partially offset by lower coal transportation costs and a reduction in our coal impairment charges.

Depreciation and amortization for 2016 decreased by $2 million compared to 2015 due to higher discount rates being applied to our decommissioning obligation for the Centralia mine. As the mine is in the reclamation stage, the adjustment flows directly to earnings.

Sustaining capital expenditures for 2016 were $2 million higher compared to 2015, primarily due to higher planned outages.

(1) Adjusted for economic dispatching.
(2) Restated to include non-operating legacy U.S. Gas costs. Refer to the Accounting Changes section of this MD&A.

2015

Production decreased 1,661 GWh in 2015 compared to 2014, as a result of a higher level of economic dispatching caused by lower prices.

In December 2014, we began supplying power to Puget Sound Energy under a 10-year contract. Initial contracted capacity was 180 MW. Contract volumes escalated to 280 MW in December 2015 and to 380 MW in 2016. We can supply the contract by buying power from the market when economical to do so and further improve our margin. The contract is accounted for as a financial contract. Hedge accounting was applied to this contract, with changes in value recorded in other comprehensive income ("OCI").

EBITDA for the year ended Dec. 31, 2015, was comparable to 2014. The appreciation of the US dollar and lower pricing on uncontracted generation was offset by the increased contracted volumes with Puget Sound Energy.

Depreciation and amortization for 2015 increased by $9 million compared to 2014 due to the strengthening of the US dollar.

For the year ended Dec. 31, 2015, sustaining capital expenditures increased by $3 million compared to last year as a result of the coal fines recovery finance lease. This operation allows us to recover fuel as part of mine decommissioning activities.

Canadian Gas

Year ended Dec. 31	2016	2015	2014
Availability (%)	**95.7**	95.6	94.9
Contract production (GWh)	**2,784**	3,697	4,096
Merchant production (GWh)	**288**	1,535	2,027
Total production (GWh)	**3,072**	5,232	6,123
Gross installed capacity (MW)[1]	**1,057**	1,057	1,183
Revenues	**470**	486	584
Fuel and purchased power	**171**	204	299
Comparable gross margin	**299**	282	285
Operations, maintenance, and administration	**54**	67	69
Taxes, other than income taxes	**1**	3	4
Comparable EBITDA	**244**	212	212
Depreciation and amortization	**108**	98	98
Comparable operating income	**136**	114	114
Sustaining capital:			
Routine capital	**7**	4	22
Planned major maintenance	**5**	19	33
Total	**12**	23	55

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor Energy ("Suncor"). We continue to own a portion of the facility and have included our portion as a part of gross capacity measures. Poplar Creek has been removed from our availability and production metrics, effective Sept. 1, 2015.

2016

Production for the year decreased 2,160 GWh compared to 2015, primarily due to the restructuring of our contract with Suncor at the Poplar Creek facility in the third quarter of 2015 and higher economic dispatching in Ontario driven by lower prices.

Comparable EBITDA for 2016 increased by $32 million compared to 2015, as result of a year-over-year change in unrealized mark-to-market on our gas position, cost-efficiency initiatives, and favourable pricing in Ontario from our contracts for power and gas. The recontracting of the Poplar Creek facility reduced our OM&A by more than $9 million in 2016, compared to last year.

Sustaining capital totalled $12 million in 2016, a decrease of $11 million. In 2015, we refurbished two engines in Ontario. The change in our Poplar Creek operation also lowered our sustaining capital by approximately $7 million compared to 2015.

2015

Production for the year ended Dec. 31, 2015, decreased 891 GWh compared to 2014, also as a result of the restructuring of our contract with Suncor at Poplar Creek, effective Sept. 1, 2015.

The Poplar Creek transaction had a minimal impact on EBITDA in 2015 compared to 2014.

Sustaining capital decreased by $32 million for the year ended Dec. 31, 2015 compared to 2014, due to the transfer of the Poplar Creek facility at the end of August, and lower planned maintenance activities resulting from condition-based assessments.

Australian Gas

Year ended Dec. 31	2016	2015	2014
Availability (%)	**93.1**	92.4	91.4
Contract production (GWh)	**1,529**	1,381	1,267
Gross installed capacity (MW)[1]	**425**	348	348
Revenues	**174**	163	159
Fuel and purchased power	**20**	20	23
Comparable gross margin	**154**	143	136

Operations, maintenance, and administration	**25**	21	33
Taxes, other than income taxes	**1**	-	-
Comparable EBITDA	**128**	122	103
Depreciation and amortization	**20**	20	16
Comparable operating income	**108**	102	87
Sustaining capital:			
Routine capital	**3**	4	2
Planned major maintenance	**11**	4	6
Total	**14**	8	8

(1) Includes production capacity for the Solomon power station, which has been accounted for as a finance lease.

2016

Production for 2016 increased 148 GWh compared to 2015 mostly from an increase in customer load. Due to the nature of our contracts, the increase did not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA for the year increased by $6 million compared to 2015, mainly due to the addition of capacity payments for the gas conversion project at our Solomon gas plant that was completed in May 2016, as well as the uplift from our natural gas pipeline that was commissioned in March 2015. The change in value of the Australian dollar had limited impact on our comparable EBITDA in 2016.

Sustaining capital increased by $6 million compared to 2015, mainly driven by maintenance projects on two engines in 2016 compared to maintenance projects on only one engine in 2015.

2015

Production for the year ended Dec. 31, 2015, increased 114 GWh compared to 2014 due to an increase in the power import regime at one of our customer's locations. Due to the nature of our contracts, the change did not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

The increase in comparable EBITDA was primarily attributable to revenue from the Australian natural gas pipeline, which was commissioned in March 2015. Revenue from our Solomon facility was also positively impacted by the appreciation of the US dollar. The Australian dollar remained at similar levels in relation to the Canadian dollar during 2015.

Most of our contracts provide for the pass-through of fuel costs to the counterparty, limiting our exposure to fluctuations in fuel prices. In the case where we have no provision for pass-through, we generally match our obligation to deliver energy and our fuel supply to minimize our exposure to volatile commodity prices. Revenue and costs of fuel decreased by similar amounts during the first half of 2015 compared to 2014, following the decrease in gas input costs. Also, certain operating costs that are transferred to customers are now billed directly to the customer, resulting in revenue and OM&A decreasing in 2015 compared to 2014.

Depreciation and amortization for 2015 increased by $4 million compared to 2014 due to the increased asset base associated with the Fortescue River Gas Pipeline completed in the first quarter of 2015.

Sustaining capital remained at similar levels in 2015 compared to 2014.

Wind and Solar

Year ended Dec. 31	**2016**	2015	2014
Availability (%)	**94.9**	95.8	94.6
Contract production (GWh)	**2,301**	2,146	2,228
Merchant production (GWh)	**1,212**	1,060	947
Total production (GWh)	**3,513**	3,206	3,175
Gross installed capacity (MW)[1]	**1,408**	1,424	1,291
Revenues	**272**	250	247
Fuel and purchased power	**18**	19	14
Comparable gross margin	**254**	231	233
Operations, maintenance, and administration	**52**	48	48

Taxes, other than income taxes	**8**	7	6
Net other operating income	**(1)**	-	-
Comparable EBITDA	**195**	176	179
Depreciation and amortization	**119**	99	88
Comparable operating income	**76**	77	91
Sustaining capital:			
Routine capital	**2**	1	2
Planned major maintenance	**11**	12	10
Total sustaining capital expenditures	**13**	13	12
Insurance recoveries of sustaining capital expenditures	**(1)**	-	-
Net amount	**12**	13	12

2016

Production for 2016 increased by 307 GWh compared to 2015, mainly due to the full year contribution from assets acquired during the second half of 2015, partly offset by lower wind resources negatively impacting generation across Canada.

Comparable EBITDA for 2016 increased $19 million compared to 2015, as assets acquired in the second half of 2015 contributed approximately $23 million to the increase. Lower merchant prices in Alberta and lower generation in Canada negatively impacted our EBITDA.

Depreciation and amortization increased by $20 million compared to 2015, primarily due to the addition of assets acquired during the second half of 2015.

2015

Production for 2015 increased slightly by 31 GWh compared to 2014, due to contributions from three additional wind farms and our first solar facility acquired during the second half of 2015 (111 GWh). This was partially offset by lower wind resources at Wyoming in 2015 compared to relatively high wind volumes in 2014.

Comparable EBITDA for 2015 was lower by $3 million compared to 2014 as lower generation from our Wyoming wind facility and lower merchant prices in Alberta were not fully offset by additional EBITDA from the acquired assets and the stronger US dollar.

Depreciation and amortization for 2015 increased by $11 million compared to 2014, primarily due to the acquisition of new assets during the year and a stronger US dollar.

(1) *Our 2015 capacity excludes acquisitions completed during the second half of 2015.*

Hydro

Year ended Dec. 31	**2016**	2015	2014
Contract production (GWh)	**1,768**	1,662	1,810
Merchant production (GWh)	**88**	86	75
Total production (GWh)	**1,856**	1,748	1,885
Gross installed capacity (MW)	**926**	926	913
Revenues	**126**	116	131
Fuel and purchased power	**8**	8	9
Comparable gross margin	**118**	108	122
Operations, maintenance, and administration	**33**	38	38
Taxes, other than income taxes	**3**	3	3
Net other operating income	**-**	(6)	(6)
Comparable EBITDA	**82**	73	87
Depreciation and amortization	**33**	25	24
Comparable operating income	**49**	48	63
Sustaining capital:			
Routine capital, excluding hydro life extension	**8**	3	9
Hydro life extension	**9**	18	19
Planned major maintenance	**10**	10	3
Total before flood-recovery capital	**27**	31	31
Flood-recovery capital	**2**	4	9
Total sustaining capital expenditures	**29**	35	40
Insurance recoveries of sustaining capital expenditures	**-**	(18)	(4)

Net amount	**29**	17	36

2016

Production for 2016 increased by 108 GWh over 2015, primarily due to better water resources.

Comparable EBITDA for 2016 increased $9 million compared to 2015. Higher generation contributed to higher revenues. Our financial contracts partially offset lower levels of revenues in the Alberta ancillary market, and we also benefited from cost-reduction initiatives implemented in late 2015.

Depreciation and amortization for 2016 increased by $8 million compared to 2015 due to the recognition of decommissioning obligations on certain transmission lines that were taken out of service. As these transmission lines are in the reclamation stage, the adjustment flows directly to earnings.

Sustaining capital (before insurance recoveries) for 2016 decreased $6 million compared to 2015 due to lower expenditures on hydro life extension projects, partially offset by higher expenditures on routine capital.

2015

Production for 2015 decreased by 137 GWh compared to 2014, primarily as a result of lower water resources.

Comparable EBITDA decreased by $14 million for 2015 compared to 2014, primarily as a result of lower prices and a decrease in price volatility in Alberta, which limited our ability to take advantage of our flexibility to produce electricity in higher-priced hours. Net other operating income includes business interruption insurance recoveries relating to the 2013 Alberta flood.

Sustaining capital expenditures (before insurance recoveries) decreased by $5 million for the year ended Dec. 31, 2015 compared to 2014 mainly due to flood-recovery capital related to the Alberta flood of 2013.

Energy Marketing

Year ended Dec. 31	**2016**	2015	2014
Revenues and comparable gross margin	**76**	49	108
Operations, maintenance, and administration	**24**	12	33
Comparable EBITDA	**52**	37	75
Depreciation and amortization	**3**	1	-
Comparable operating income	**49**	36	75

Comparable EBITDA from Energy Marketing increased $15 million compared to 2015, as a result of solid performances in all markets where we are active. During the second quarter of 2015, unexpectedly volatile markets in Alberta and the Pacific Northwest negatively impacted gross margin. Operating, maintenance, and administration costs increased $12 million to $24 million in 2016 compared to 2015, due to increases in share-based incentive compensation and lower charges to other business segments for energy hedging and optimization services.

Corporate

Our Corporate overhead costs of $70 million were lower in 2016 compared to 2015 and 2014 ($72 million and $71 million, respectively), as we realized benefits of cost-efficiency initiatives that were offset by reduced allocations to our business segments.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. We are focused on strengthening our financial position and flexibility and aim to meet all our target ranges by 2018.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

As at Dec. 31	**2016**	2015	2014
Comparable FFO	**763**	740	762
Add: Interest on debt net of capitalized interest	**223**	223	236
Comparable FFO before interest	**986**	963	998
Interest on debt	**239**	232	239
Add: 50 per cent of dividends paid on preferred shares	**21**	23	21
Adjusted interest	**260**	255	260
Comparable FFO before interest to adjusted interest coverage (times)	**3.8**	3.8	3.8

Our target for comparable FFO before interest to adjusted interest coverage is four to five times. This ratio is comparable to last year, as 2016's higher comparable FFO was offset by higher interest on debt, which includes interest capitalized on our South Hedland power project. We expect this metric to improve towards our targeted level in the future, due the South Hedland power project, once commissioned.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

As at Dec. 31

	2016	2015	2014
Comparable FFO	**763**	740	762
Less: 50 per cent of dividends paid on preferred shares	**(21)**	(23)	(21)
Adjusted comparable FFO	**742**	717	740
Period-end long-term debt[1]	**4,361**	4,495	4,056
Less: Cash and cash equivalents	**(305)**	(54)	(43)
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt[2]	**(163)**	(190)	(96)
Adjusted net debt	**4,364**	4,722	4,388
Adjusted comparable FFO to adjusted net debt (%)	**17.0**	15.2	16.9

Our adjusted comparable FFO to adjusted net debt ratio improved to 17.0 per cent, mostly due to the increase in comparable FFO, and lower net debt due to repayments, and the strengthening of the Canadian dollar in 2016. We expect this metric to improve towards our targeted level of 20 to 25 in the future, due the South Hedland power project, once commissioned.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	**2016**	2015	2014
Period-end long-term debt[1]	**4,361**	4,495	4,056
Less: Cash and cash equivalents	**(305)**	(54)	(43)
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt[2]	**(163)**	(190)	(96)
Adjusted net debt	**4,364**	4,722	4,388
Comparable EBITDA[1]	**1,145**	945	1,036
Adjusted net debt to comparable EBITDA (times)	**3.8**	5.0	4.2

During the year, our adjusted net debt to comparable EBITDA ratio improved compared to 2015, mainly because of a lower debt balance due to repayments and the strengthening of the Canadian dollar, and higher comparable EBITDA. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. We expect this metric to improve towards our targeted level in the future due to the expected increase in comparable EBITDA of approximately $80 million annually from the South Hedland power project, once commissioned.

Sustainability Performance

Stakeholder Communication and Value Creation

The information contained herein seeks to highlight our ability to create value for investors, stakeholders, and society in the short, medium, and long term. The selection of key information and key metrics disclosed in this integrated report and our full sustainability disclosures follow a materiality assessment process, which identifies key impact areas to our stakeholders. We subsequently are guided by, and place focus on, reporting on these key areas. More information on key areas of materiality can be found on the sustainability section of our website.

(1) Includes finance lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2016, Dec. 31, 2015, and Dec. 31, 2014.

Sustainability Targets and Results

Sustainability targets are strategic goals that support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas.

2016 Sustainability Targets			
	Financial	**Results**	**Comments**
1. Maintain our investment grade rating	Achieve and maintain investment grade credit metrics	Partly achieved	TransAlta maintains investment grade ratings from three rating agencies: S&P (BBB-) stable, DBRS (BBB) negative outlook, and Fitch (BBB-) negative outlook. On Dec. 17, 2015, Moody's reduced our rating to Ba1
2. Increase focus on FFO and EBITDA	TransAlta targeted comparable EBITDA and comparable FFO for 2016 in the range of $990 million to $1,100 million and $755 million to $835 million respectively	Achieved	For the year ended Dec. 31, 2016, comparable EBITDA was $1,145 million and comparable FFO was reported at $763 million. Comparable EBITDA includes the reversal of provisions relating to the Keephills 1 force majeure event in the amount of $80 million

	Power Generating Portfolio	**Results**	**Comments**
3. Grow asset portfolio	Deliver an average of $40 million to $60 million of additional EBITDA from growth projects	On track	In 2016, we continued to exercise prudence and discipline in growing our cash flow. The wind and solar pojects acquired in late 2015 contributed approximately $25 million of comparable EBITDA in 2016. We continue to advance the construction of the South Hedland power project, on budget and on time. This project is expected to be commisioned by mid-2017 and add approximately $80 million of incremental annualized EBITDA

4. Achieve top-quartile performance in Canadian Coal	Continue to deliver 87 to 89 per cent availability in the segment	Not achieved	We achieved availability in 2016 of 85.3 per cent, compared to 84.3 per cent in 2015, lower than our targeted availability of at least 87 per cent. Our high level of contracted generation and hedging strategy mitgated lower power prices in Alberta. We continue to drive towards our targets

	Human and Intellectual	**Results**	**Comments**
5. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.70	Not achieved	IFR was 0.85 in 2016, up from 0.75 in 2015. We will continue to seek improvement in this area through deployment of additional targeted initiatives in 2017
6. Human Resources	a) Maintain voluntary turnover percentage under eight per cent	Achieved	Voluntary turnover was 6.7 per cent in 2016
	b) Achieve 100 per cent completion of development plans for all high-potential employees at the top three levels of the organization	Achieved	
	c) Complete the final three stages of our globally recognized leadership development project to ensure TransAlta's top three levels of leaders have the tools to successfully reposition and grow our business	Partly achieved	Final stages to be completed in Q1 2017

	Natural	**Results**	**Comments**
7. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 13	Not achieved	We recorded 16 reportable environmental incidents in 2016, none of which had a material environmental impact
8. Increase mine reclaimed acreage	Replace annual topsoil rate at Highvale mine at a rate of 74 acres/year	Partly achieved	Replaced topsoil on 38 acres in 2016. A warmer winter and early spring limited our ability to transport topsoil for placement without adversely impacting the ground surface (the preference is to drive on frozen soil)
9. Utilize coal byproduct	Sell a minimum of two million tonnes of coal byproduct materials during the period 2015 to 2017	On track	70 per cent achieved (long-term target)
10. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NO_x and SO_2 emissions by 2030	On track	We reduced levels of NO_x and SO_2 in 2016 and remain on track to realize these emission reductions by 2030
11. Reduce greenhouse gas emissions	a) 20 per cent reduction from 2005 levels of TransAlta coal facility GHG by 2021, or the equivalent of 7 million tonnes, of CO_2e per year	On track	We reduced GHG emissions in 2016, primarily as a result of lower coal production, and we remain on track to realize emission reductions by 2021/2030
	b) 55 per cent reduction from 2005 levels by 2030, or the equivalent of 19.7 million tonnes, of CO_2e per year.	On track	

	Social and Relationship Capital	**Results**	**Comments**
12. Combine stakeholder engagement	Implement final Stakeholder Engagement Framework. In 2016, every business unit will use a single framework for stakeholder guidance	Achieved	A corporate-wide framework was implemented and we introduced our Stakeholder and Aboriginal Relations ("STAR") tracking program. STAR is a communication record-keeping tool and fulfils our requirements for consultation with both stakeholders and aboriginal groups
13. Support youth education with community investment	50 per cent of total communitiy investment spending will be directed to supporting youth education	Partly achieved	In 2016 we spent approximately $0.75 million out of $2.5 million (30 per cent) on youth education. Funds were directed to the University of Calgary, University of Alberta, Southern Alberta Institute of Technology, Mount Royal University, The Banff Centre (indigenous leadership scholarships), Mother Earth's Children's Charter School (indigenous kindergarten to grade 9), Calgary Stampede (the Young Canadians - ages 7 to 18) and national Canada and U.S. indigenous scholarships (post-secondary for trades and academic)

14. Increase internal best practice aboriginal engagement awareness	Work with our aboriginal communities to develop an online best practice guide for employees on working with and engaging with aboriginal communities	Achieved	With the help of the First Nations groups and voices of those communities, we produced an Indigenous Awareness Training handbook for all our employees. This achievement is in line with a commitment to support the United Nations Sustainable Development Goals, specifically, goal 10: reduced inequalities

Competitive Forces

Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity, whereas system capacity, natural gas prices, GHG pricing, government subsidies, and renewable resource availability are key drivers to the supply. Growth in behind-the-fence generation for mining investments is key to developing our Australian gas segment.

Renewable capacity addition has been strong for the past several years due to government incentives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy as well as natural-gas-fired generation. This expectation is driven by the low prices in the natural gas market combined with public policies that favour carbon emission reductions.

We have substantial merchant capacity in Alberta and the Pacific Northwest. In those regions, we enter into contracts and business relationships with commercial and industrial customers to sell power on a long-term basis, up to our available capacity in the markets. We further reduce the portion of production not sold in advance through short-term physical and financial contracts, and we optimize production in real time against our position and market conditions.

We also compete for long-term contracted opportunities in renewable and gas power generation, including cogeneration, across Canada, the United States, and Australia. Our target customers in this area are incumbent utility providers and large industrial and mining operators.

Alberta

Approximately 63 per cent of our gross capacity is located in Alberta and more than 65 per cent of this is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. Alberta PPAs expire at the end of 2017 (Sundance 1 and 2) and the end of 2020 (Keephills 1 and 2, Sundance 3 to 6, Sheerness, and Hydro). Coal generation sold under Alberta PPAs retains some exposure to market prices as we pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of energy and ancillary services in excess of obligations on our Hydro Alberta PPAs (“hydro peaking”). We enter into financial contracts to reduce our exposure to variable power prices for a significant portion of our remaining generation.



Following the decrease in oil prices, Alberta’s annual demand for power decreased by approximately 1.1 per cent in 2016 compared to 2015. Since 2014, approximately 1,000 MW of gas and wind generation capacity were added to the market. As a result, power pool prices trended to their lowest levels in the last 10 years, dropping to an average of $18/MWh in 2016, due to an oversupply of energy as well as bidding behaviour in the market that kept prices low. The decline impacted merchant wind and hydro peaking, which are the portions of our portfolio we cannot effectively hedge.

Our current share of offer control in the province is approximately 12 per cent. After the expiry of the PPAs at the end of 2020, our share of offer control is forecast to increase to approximately 28 per cent depending on load and supply growth in the province.

In late November 2016, we announced that we had entered into an OCA with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. We also entered into the MOU with the Government of Alberta to collaborate and co-operate in the development of a capacity market in Alberta that ensures both current and new electricity generators will have a level economic playing field to build, buy, and sell electricity, and to develop a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation. We expect additional compliance costs as a result of the federal government’s proposed framework in which each province is expected to implement a greenhouse gas (“GHG”) policy equivalent to a carbon price of $50 per tonne by 2022. We believe that our extensive portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro, and gas that give us a cost advantage over competitors when constructing generation facilities that use these fuel types.

In March and May 2016, the buyers under the legislated Sundance, Sheerness, and Keephills PPAs announced their intention to terminate the PPAs and transfer their respective obligations under the PPAs to the Balancing Pool because of a change in Alberta law. Accordingly, the Balancing Pool began its investigation to determine whether these transfers are permitted by the terms of the PPAs in the current circumstances and, if so, when the transfers would become effective. On July 25, 2016, the Attorney General for the Province of Alberta commenced legal proceedings seeking relief against: all buyers who purported to transfer their respective obligations under the PPAs, the owner of the Battle River #5 PPA, the Alberta Utilities Commission (“AUC”), and the Balancing Pool. In this claim, the Attorney General challenges, among other things, the basis on which the buyers purported to terminate the PPAs and transfer their PPA obligations to the Balancing Pool.

Recently, the Attorney General announced that it entered into settlement agreements with the buyers of the PPAs for Sheerness, Sundance A, Sundance B, and Sundance C, and therefore discontinued its claims against those buyers. As part of the settlement, the Balancing Pool confirmed the terminations of the

PPAs for Sheerness and Sundance A, B, and C and, as a result, the Balancing Pool assumed the role of buyer and is carrying out the responsibilities of the buyer under each of those PPAs, including dispatching the generating units and making the capacity and energy payments to TransAlta until the end of the PPA terms. TransAlta does not presently expect the transfer of the role of PPA buyer to the Balancing Pool to have a material impact on its business.

Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool may also choose to terminate the PPAs after following the legislative requirements, which would include paying TransAlta an amount essentially equal to the applicable closing net book value of the generating units.

The Attorney General has not entered into a settlement agreement with the buyer under the Keephills PPA and the Balancing Pool has not confirmed the termination of that PPA. The outcome of the Attorney General's proceeding and any investigation by the Balancing Pool into the purported termination of the Keephills PPA is uncertain.

Notwithstanding all the above events, TransAlta continues to operate the PPA generating units in their ordinary course and receives the capacity and energy payments due to TransAlta under the PPAs.

U.S. Pacific Northwest

Our capacity in the U.S. Pacific Northwest is represented by our 1,340 MW Centralia coal plant. Half of the plant capacity is scheduled to retire at the end of 2020 and the other half at the end of 2025.



System capacity in the region is primarily comprised of hydro and gas generation, with some wind additions over the last few years in response to government programs favouring renewable generation. Demand growth in the region has been limited and further constrained by emphasis on energy efficiency. Our coal plant can effectively compete against gas generation, although depressed gas prices following the expansion of shale gas production in North America has added to the downward pressure on power prices.

Our competitiveness is enhanced by our long-term contract with Puget Sound Energy for up to 380 MW over the remaining life of the facility. The contract and our hedges allow us to satisfy power requirements from the market when prices fall below our marginal cost of production.

We maintain an opportunity to redevelop Centralia as a gas plant after coal capacity retires, with permitting provided for in our agreement for coal transition established with the State of Washington in 2011.

Contracted Gas and Renewables

The market for developing or acquiring gas and renewable generation facilities is highly competitive in all markets in which we operate. Our solid record as operator and developer supports our competitive position. We expect, where possible, to reduce our cost of capital and improve our competitive profile by using project financing and leveraging the lower cost of capital with TransAlta Renewables. In the United States, our substantial tax attributes further increase our competitiveness.

While depressed commodity prices have reduced sectoral growth in the oil, gas, and mining industries, the change is also creating opportunities for us as a service provider as some of our potential customers are more carefully evaluating non-core activities and driving for operational efficiencies. In renewables, we are primarily evaluating greenfield opportunities in Western Canada or acquisitions in other markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities.

Some of our older gas plants are now reaching the end of their original contract life. The plants generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these plants with limited life-extending capital expenditures. We have recently extended the life of our Ottawa (2033 expiry), Windsor (2031 expiry), and Parkeston (2026 expiry) plants in this manner. During the fourth quarter of 2016, we entered into a new contract with the IESO for our Mississauga cogeneration facility. The new contract took effect on Jan. 1, 2017, and has resulted in the termination of the existing contract, which would have otherwise terminated in December 2018. See the Significant Events section for further details. The new contract provides us with additional financial flexibility to pay down upcoming debt maturities.

TransAlta's Capital

The following discusses TransAlta's main categories of capital, being Financial, Power Generating Portfolio, Human and Intellectual, Social and Relationship, and Natural.

Financial Capital

Sources of Capital

Our goal over the last two years was to build financial flexibility by using multiple sources of funding to reposition our capital structure. Over the last few years, the rating of our unsecured debt was put under pressure by all the rating agencies.[1] We responded to this pressure by taking significant action starting in 2014 and through to today to reduce our indebtedness and work on strengthening our financial metrics. Since the end of 2013, senior unsecured debt has been reduced by $1.1 billion, including a reduction of over $800 million on our credit facility and a $300 million reduction in Canadian and U.S. bonds. Over the next two years, we plan to continue on this path by replacing an additional $700 million to $900 million of maturing recourse debt with debt secured by contracted cash flows.

On Dec. 17, 2015, Moody's lowered the rating of our senior unsecured debt to Ba1 with a stable outlook. The direct financial impact of this downgrade has been limited. We have posted additional collateral (including letters of credit) of nearly $130 million to certain counterparties, and the cost of borrowing under our credit facilities and US$400 million of debt has been stepped up in line with contractual provisions. During the first quarter of 2016, DBRS and Fitch Ratings ("Fitch") changed their outlooks from stable to negative. Their negative outlooks are a reflection of low energy prices and concerns over coal generation transition in Alberta. We have investment grade ratings from each of DBRS, S&P, and Fitch. We remain focused on maintaining these ratings, as

strengthening our financial position allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are favourable to our financial results and provides us with better access to capital markets through commodity and credit cycles. Risks associated with further reductions in our credit ratings are discussed in the Liquidity Risk section of this MD&A.

---

(1) As at Dec. 31, 2016, our senior unsecured debt is rated as investment grade by three rating agencies: BBB (negative), BBB- (stable), and BBB- (negative) by DBRS, Standard and Poor's ("S&P"), and Fitch Ratings ("Fitch"), respectively, and Ba1 (stable) by Moody's Investors Service ("Moody's"). Our preferred shares are rated P-3 (stable) and Pfd-3 (negative) by S&P and DBRS, respectively. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to our outstanding securities by DBRS, S&P, Moody's, and Fitch, as applicable, are not recommendations to purchase, hold, or sell such securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by DBRS, S&P, Moody's, or Fitch in the future if, in their judgment, circumstances so warrant. See the Liquidity Risk section of this MD&A.

Capital Structure

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

	2016		2015		2014	
As at Dec. 31	**$**	**%**	$	%	$	%
Recourse debt - CAD debentures	**1,045**	**12**	1,044	12	1,043	13
Recourse debt - U.S. senior notes	**2,151**	**25**	2,221	26	2,444	31
Credit facilities	**-**	**-**	315	4	96	1
U.S. tax equity financing	**39**	**1**	50	1	-	-
Other	**15**	**-**	17	-	19	-
Less: cash and cash equivalents	**(305)**	**(4)**	(54)	(1)	(43)	-
Less: fair value asset of hedging instruments on debt	**(163)**	**(2)**	(190)	(2)	(96)	(1)
Net recourse debt	**2,782**	**32**	3,403	40	3,463	44
Non-recourse debt	**1,038**	**12**	766	9	380	5
Finance lease obligations	**73**	**1**	82	1	74	1
Total net debt	**3,893**	**45**	4,251	50	3,917	50
Non-controlling interests	**1,152**	**14**	1,029	12	594	8
Equity attributable to shareholders						
Common shares	**3,094**	**36**	3,075	35	2,999	38
Preferred shares	**942**	**11**	942	11	942	12
Contributed surplus, deficit, and accumulated other comprehensive income	**(525)**	**(6)**	(656)	(8)	(657)	(8)
Total capital	**8,556**	**100**	8,641	100	7,795	100

During 2016, we continued to work on strengthening our financial position and executing on our debt deleveraging strategy. Our total debt, net of cash on hand and the fair value of our financial instruments hedging our U.S. debt, was reduced by more than $350 million, from a combination of cash flows from operations and cash proceeds of $173 million received from the sale of the economic interest in the Canadian Assets. Furthermore, we extended $1.8 billion of our $2.0 billion credit facilities to 2020 and the remaining were extended to 2018. Since 2014, we acquired one wind and five solar projects for a total consideration of approximately $200 million, including the assumption of debt. These projects contributed approximately $25 million of comparable EBITDA in 2016. We also funded $336 million for the construction of the South Hedland project. In total, the South Hedland project is expected to cost approximately $576 million and add $80 million of EBITDA annually over the 25-year life of the long-term contract (including approximately $29 million of EBITDA relating to TransAlta Renewables' non-controlling interest share). We expect the project to commence operations in mid-2017.

During the year, we continued implementing our strategy to raise debt secured by our contracted cash flows and completed the following debt offerings:

- a non-recourse bond in the amount of $202.5 million, with principal and interest payable quarterly, maturing on Dec. 31, 2030, secured by our Poplar Creek finance lease contract, and
- a non-recourse bond in the amount of $159 million, with principal and interest payable semi-annually, and maturing on June 30, 2032, secured by our New Richmond Wind project in Quebec.

In 2015, we completed a $442 million bond offering, secured by two wind projects located in Ontario. The bonds are non-recourse to TransAlta, amortizing, and bear interest at a rate of 3.8 per cent, payable semi-annually, and mature on Dec. 31, 2028. On Feb 11, 2015, we also refinanced our $35 million 5.28 per cent Pingston non-recourse debt with a $45 million 2.95 per cent non-recourse bond due in full in 2023. We also added $105 million of non-recourse debt relating to the acquisitions of two renewable facilities in the U.S.

Non-recourse debt of $845 million in total (2015 - $536 million) is subject to customary financing restrictions that restrict our ability to access funds generated by certain facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. At Dec. 31, 2016, $24 million of cash was subject to these financial restrictions. Non-recourse debts of $644 million are each secured by a first ranking charge over all of the respective assets of our subsidiaries that issued the bonds, which includes renewable generation facilities with total carrying amounts of $956 million at Dec. 31, 2016 (2015 - $798 million). A non-recourse bond of approximately $201 million is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The weakening of the US dollar has decreased our long-term debt balances by $67 million in 2016. Almost all our U.S.-denominated debt is hedged either through financial contracts or net investments in our U.S. operations. During the period, these changes in our U.S.-denominated debt were offset as follows:

As at Dec. 31	2016	2015
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	**(35)**	201
Foreign currency cash flow hedges on debt	**(29)**	183
Economic hedges and other	**(3)**	8
Total	**(67)**	392

Over the next four years, we have approximately $2.2 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising $700 million to $900 million of debt secured by our contracted cash flows. We also expect to continue our deleveraging strategy, as a significant part of our free cash flow over the next four years will be allocated to debt reduction. The reduction of our common share dividend in January 2016 is expected to provide additional funds which may be used for debt reduction.

Our credit facilities provide us with significant liquidity. At Dec. 31, 2016, we had a total of $2.0 billion (2015 - $2.2 billion) of committed credit facilities, of which $1.4 billion (2015 - $1.3 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2016, the $0.6 billion (2015 - $0.9 billion) of credit utilized under these facilities was comprised of actual drawings of nil (2015 - $0.3 billion) and letters of credit of $0.6 billion (2015 - $0.6 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility expiring in 2020, one bilateral credit facility of US$200 million, expiring in 2020, and three bilateral credit facilities, totalling $240 million, expiring in 2018.

Working Capital

Including the current portion of long-term debt, the excess of current assets over current liabilities was $337 million as at Dec. 31, 2016 (2015 - $311 million). Although our working capital has not changed significantly, the timing of the classification of long-term debt as current has negatively impacted our current period-end working capital. Excluding the current portion of long-term debt of $639 million, the excess of current assets over liabilities was $976 million as at Dec. 31, 2016 (2015 - $398 million). Working capital as at Dec. 31, 2016, also includes approximately $93 million of receivables related to the Mississauga recontracting and $61 million related to the Wintering Hills wind facility reclassified as assets held for sale. Last year, working capital included a $59 million provision relating to the Keephill 1 outage. We reversed a total of $94 million of this provision in the fourth quarter of 2016.

Share Capital

Our Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares reset in 2016 at a coupon rate of 2.709 per cent. As permitted under the terms of the Preferred Shares, some shareholders elected to convert to a floating rate and 1,824,620 of our 12 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares.

The following tables outline the common and preferred shares issued and outstanding:

As at	March 2, 2017	Dec. 31, 2016	Dec. 31, 2015
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	284.0
Preferred shares			
Series A	10.2	10.2	12.0
Series B	1.8	1.8	-
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

The Series C and Series E preferred shares will also reset in 2017. The rate spread on the Series C and Series E over the then 5-year Government of Canada bond rate is 3.10 per cent and 3.65 per cent, respectively.

Non-Controlling Interests

As of Dec. 31, 2016, we own 64.0 per cent (2015 – 66.6 per cent) of TransAlta Renewables. On January 2016, we completed the sale to TransAlta Renewables of an economic interest in the 506 MW Sarnia cogeneration facility and of two renewable energy facilities with total capacity of 105 MW for $540 million. Consideration received from TransAlta Renewables consisted of gross proceeds from a public offering of 17,692,750 common shares at $9.75 per share for gross proceeds of $173 million, 15.6 million common shares of TransAlta Renewables with a value of $152 million, and a $215 million unsecured subordinated debenture convertible into common shares of TransAlta Renewables at a price of $13.16 per common share upon maturity on Dec 31, 2020. In November 2016, the economic interest was converted to direct ownership of the Canadian Assets by TransAlta Renewables.

TransAlta Renewables is a publicly traded company whose common shares are listed on the Toronto Stock Exchange under the symbol “RNW”. TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity. The stable and predictable cash flows generated by these assets has attracted favourable equity valuations from investors, allowing TransAlta to raise equity capital.

In November 2015, we sold 20.5 million common shares of TransAlta Renewables in a private placement to AIMCo for net cash consideration of $193 million.

On May 7, 2015, we completed the sale of an economic interest in our Australian assets to TransAlta Renewables. The Australian assets consist of six operating assets with an installed capacity of 425 MW, the 150 MW South Hedland project currently under construction, as well as a 270-kilometre gas pipeline, for total consideration of $1.78 billion. At the closing of the transaction, TransAlta Renewables paid the Corporation $217 million in cash as well as approximately $1,067 million through a combination of common shares and Class B shares in TransAlta Renewables. TransAlta Renewables has also committed to funding the costs to construct the South Hedland project incurred after Jan. 1, 2015, representing an estimated amount of $474 million. TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 common shares at a price of $12.65 per share.

We remain committed to maintaining our position as the majority shareholder and sponsor of TransAlta Renewables with a stated goal of maintaining our interest between 60 to 80 per cent.

We also own 50.01 per cent of TransAlta Cogeneration L.P ("TA Cogen"), which owns, operates, or has an interest in three natural-gas-fired facilities and one coal-fired generating facility. We recently recontracted our Mississauga cogeneration facility, which resulted in a pre-tax gain of approximately $191 million, accelerated depreciation of $46 million, and a fuel charge for the de-designation of gas hedges of $14 million. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets, and liabilities in relation to those assets.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	**2016**	2015	2014
Interest on debt	**236**	228	238
Loss on redemption of bonds	**1**	-	-
Capitalized interest	**(16)**	(9)	(3)
Interest on finance lease obligations	**3**	4	1
Other	**(5)**	(2)	(1)
Keephills 1 outage interest accruals (reversals)	**(10)**	9	1
Accretion of provisions	**20**	21	18
Net interest expense	**229**	251	254

Net interest expense decreased in 2016 compared to 2015, primarily as a result of higher capitalized interest relating to the South Hedland power project and the reversal of the accrued interest component of the Keephills 1 provision. See the Other Consolidated Analysis section of this MD&A for further details. These decreases were partially offset by higher interest on debt, due partially to the downgrade to our credit rating from Moody's and higher average interest rates in 2016 as compared to 2015.

For the year ended Dec. 31, 2015, net interest expense decreased compared to 2014, primarily due to the reduction in debt during the year and lower interest rates on debt that was refinanced, coupled with higher capitalized interest. Higher interest expense on foreign-denominated debt due to the strengthening of the US dollar and other interest expense associated with the adjustment to provisions have partially offset these decreases.

Dividends to Shareholders

On Jan. 14, 2016, we announced a reduction of our common share dividend from $0.72 annually to $0.16 annually. This action was taken as part of a plan to improve our long-term financial flexibility. The declaration of dividends is at the discretion of the Board.

The following are the 2016 common and preferred shares dividends declared each quarter:

	Common dividends	Preferred Series dividends per share				
Year ended Dec. 31, 2016	**per share**	**A**	**B**	**C**	**E**	**G**
First quarter	0.04	0.2875	-	0.2875	0.3125	0.33125
Second quarter	0.04	0.16931	0.15490	0.2875	0.3125	0.33125
Third quarter	0.04	0.16931	0.16144	0.2875	0.3125	0.33125
Fourth quarter	0.04	0.16931	0.15974	0.2875	0.3125	0.33125
Fourth quarter [(1)]	0.04	0.16931	0.15651	0.2875	0.3125	0.33125

During the year ended Dec. 31, 2016, 3.9 million (2015 – 9.0 million) common shares were issued to shareholders that elected to reinvest their dividends, for a total of $18 million (2015 - $76 million). On Jan. 14, 2016, we suspended the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP").

(1) On Dec. 19, 2016 the Board declared quarterly dividends per common share and preferred shares payable to shareholders of record at the close of business on March 1, 2017.

Non-Controlling Interests

Comparable earnings attributable to non-controlling interests for the year ended Dec. 31, 2016 increased, $23 million to $103 million compared to 2015, primarily due to the public offering of additional common shares by TransAlta Renewables to finance its investments in the Australian and Canadian portfolios in May 2015 and January 2016, respectively.

In 2015, comparable earnings attributable to non-controlling interests increased $31 million to $80 million compared to 2014, primarily due to the additional common shares issued to the public by TransAlta Renewables to fund its investment in the Australian portfolio.

Ability to Deliver Financial Results

The metrics we use to track our performance are comparable EBITDA, comparable FFO, and comparable FCF.The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		**2016**	2015	2014
Comparable EBITDA	Target	**990 - 1,100**	1,000 - 1,040	1,015 - 1,065

	Actual[1]	**1,145**	945	1,036
Comparable FFO	Target	**755 - 835**	720 - 770	743 - 793
	Actual	**763**	740	762
Comparable FCF	Target	**250 - 300**	265 - 270	274 - 324
	Actual	**299**	315	280

Power Generating Portfolio Capital

We monitor availability closely as a key metric to achieving our financial targets. We adjust our maintenance and sustaining capital expenditures to optimize financial returns on our investments and to align with our strategic orientations.

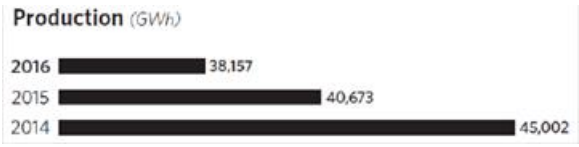
Availability and Production

Our adjusted availability target was 89 to 91 per cent for 2016.

Our availability in 2016, after adjusting for economic dispatching at U.S. Coal, was 89.2 per cent (2015 - 89.0 per cent, 2014 - 90.5 per cent) and was comparable to last year. Lower outages and derates at Canadian Coal were mostly offset by higher unplanned outages at our Eastern Wind facilities. Similar availability year-over-year did not impact our performance metrics.



Production for the year ended Dec. 31, 2016, decreased 2,516 GWh compared to 2015, primarily due to the Poplar Creek restructuring that occurred in late 2015 and lower generation from our coal portfolio due to lower prices in the Pacific Northwest and Alberta. Under our new arrangement with Suncor, they now operate the facilities and pay us a fixed monthly fee. Production from renewable assets acquired in the second half of 2015 contributed to partially offset generation lost from Poplar Creek. The Pacific Northwest continues to be dampened by lower prices, where it was more economic to supply our contractual obligation by buying power in the market, rather than through our own generation. In Alberta, lower prices impacted both paid and unpaid curtailments in 2016.



(1) Over the last three years we have had a track record of delivering financial results well within or above guidance. Comparable EBITDA in 2015 and 2016 was impacted by non-cash adjustments related to the Keephills 1 provision. Excluding these adjustments, our Comparable EBITDA would have been $1,065 million in 2016 and $1,004 million in 2015.

Operational

In the generation segments, our OM&A costs reflect the cost of operating our facilities. These costs can fluctuate due to the timing and nature of planned and unplanned maintenance activities. The remainder of OM&A costs reflect the cost of day-to-day operations.

OM&A costs were $22 million lower in 2016 compared to 2015 as we realized benefits from our cost control and targeted productivity initiatives. Over the last two years we reduced our OM&A costs by almost $40 million. The Poplar Creek restructuring also reduced OM&A costs throughout the year as the facility falls outside our operational scope.

The following table outlines our generation comparable OM&A over the last three years:

	2016	2015	2014
Generation comparable OM&A	**396**	418	433

We continuously drive for the cost-effective operation of our facilities. In 2015, we introduced multiple initiatives to reduce our overhead and increase efficiency and productivity at Canadian Coal. Aside from the reduction in the number of positions in Canadian Coal, we have driven reductions in coal costs through improved mine planning and mining methodologies, reduced equipment requirements, and optimized contractor usage.

Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital that ensures our facilities operate reliably and safely over a long period of time. Sustaining capital also includes capital required following the 2013 flood in Alberta, most of which has been recovered from third parties.

Year ended Dec. 31	**2016**	2015	2014
Routine capital	**83**	101	135
Mine capital	**23**	25	45
Planned major maintenance	**148**	162	162
Finance leases	**16**	13	10
	270	301	352
Flood-recovery capital	**2**	4	9
Total sustaining capital expenditures	**272**	305	361
Insurance recoveries of sustaining capital expenditures	**(1)**	(25)	(4)

Net amount	**271**	280	357

Lost production as a result of planned major maintenance is as follows:

Year ended Dec. 31	**2016**	2015	2014
GWh lost[(1)]	**938**	1,409	1,519

(1) Lost production excludes periods of planned major maintenance at U.S. Coal, which occur during periods of economic dispatching.

Total sustaining capital expenditures were $33 million lower compared to 2015. At Canadian Coal, sustaining capital expenditures decreased by $21 million compared to 2015, mainly due to a reduction in maintenance projects without impacting our availability. At our Canadian Gas segment, sustaining capital expenditures decreased by $11 million compared to 2015, as we have been able to reschedule a large inspection of our gas generation units at Sarnia due to a lower number of operating hours. At our Australian Gas segment, planned major maintenance was up by $7 million in 2016 compared to 2015, driven by maintenance projects on two engines at our Kambalda and Kalgoorlie plants.

Strategic Growth

In 2016 we continued to explore opportunities to grow our cash flow but remained prudent and disciplined before allocating capital. We are focused on highly contracted gas and renewable power generation to support our financial position as we transition to having increased merchant capacity in Alberta post-2021. All investments are subject to due diligence procedures and are ultimately reviewed by our investment committee (refer to the Governance and Risk Management section of this MD&A).

Our South Hedland power project continues to progress in line with expectations. At the end of 2016 construction work was largely complete and the project team is now focusing on commissioning activities. The combined-cycle gas turbines achieved first fire in the fourth quarter and commissioning activities continue on these units. We expect to invest $230 million to $250 million to complete the construction of South Hedland, for a total cost of $576 million. We continue to expect the project to be delivered on schedule and on budget in mid-2017. The project is expected to add an additional $80 million of EBITDA annually, when fully in service.

In 2015 we completed two transactions and acquired:

- 71 MW of fully contracted renewable generation assets for cash consideration of US$76 million together with the assumption of certain tax equity obligations and US$42 million of non-recourse debt. The assets acquired include 21 MW of solar projects located in Massachusetts and the 50 MW Lakeswind wind project located in Minnesota. The assets are contracted under long-term power purchase agreements ranging from 20 to 30 years.
- As part of the restructuring of our Poplar Creek contract, we acquired the 20 MW Kent Breeze wind facility located in Ontario, which has a 20-year contract with the Ontario IESO and a 51 per cent interest in an 88 MW non-contracted wind facility in Alberta. Our interest in the Alberta wind facility was sold in early 2017.

During 2015, we received approval from the AUC to construct and operate an 856 MW combined-cycle natural-gas-fired power plant in Alberta. The Sundance 7 project has received all regulatory approvals after receiving the *Environmental Protection and Enhancement Act* approval from Alberta Environment and Parks on Oct. 1, 2015. Construction of Sundance 7 will not commence until we have contracted a significant portion of the plant capacity. Following changes to market conditions in Alberta during the last few years, we do not anticipate that this condition will be met before the next decade. In December 2015, we repurchased our partner's 50 per cent share in TAMA Power, the jointly controlled entity developing this project, for consideration of $10 million payable over five years, along with an option permitting the partner to buy back into this project or into other projects of TAMA Power during this period.

Contractual Profile

Approximately 73 per cent of our capacity over the next two years is sold under long-term contracts. Excluding Alberta PPAs for our coal and hydro facilities, the majority of these contracts have maturities in excess of 10 years. In 2016, we entered into a long term contract for the Akolkolex hydro facility in B.C., expiring in 2045. Our South Hedland power project is expected to commence operations mid-2017, which will add stable contracted cash flows until the end of its 25-year contract life. Last year, significant contracts were extended at our Poplar Creek, Windsor, and Parkeston facilities, as discussed in more detail below. The average life of these contracts is approximately 12 years.

With most of our coal and hydro facilities in Alberta rolling off the Alberta PPAs at the end of 2020, we continue to develop a portfolio of commercial and industrial customers to sell our generation to the province. We are now serving a portfolio of approximately 450 MW.

Poplar Creek

In late 2015, we closed the restructuring of our contractual arrangement for power generation services with Suncor at Suncor's oil sands base site near Fort McMurray and the acquisition of Suncor's interest in two wind projects located in Alberta and Ontario.

The Poplar Creek cogeneration facility had been built and contracted to provide steam and electricity to Suncor until 2023. Under the terms of the new

arrangement, Suncor acquired from TransAlta two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the cogeneration facility, including responsibility for all capital costs and the right to use the full 244 MW capacity of TransAlta's gas generators until Dec. 31, 2030. We provide Suncor with technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030.

As part of the arrangement, we acquired Suncor's 20 MW Kent Breeze wind facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills merchant wind facility located in Alberta. The Kent Breeze facility has a 20-year contract with the Ontario IESO. On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million.

The Poplar Creek transaction creates value by increasing the duration of the contract to 2030 from the prior 2023 expiry, while the sale of Wintering Hills reduces our exposure to Alberta's merchant power market, and allows us an injection of near-term liquidity and financial flexibility to pay down debt. Additionally, we were able to further leverage our interest in the Poplar Creek cogeneration facility by completing a private placement in late December, of $202.5 million bonds that mature in 2030 and are secured by a first ranking charge over the equity interests of the issuer that issued such bonds, further allowing us to deleverage our corporate debt.

Windsor
During the first quarter of 2015, we executed a new 15-year power supply contract with the Ontario IESO for our Windsor facility, which was effective Dec. 1, 2016. The contract is similar to the contract signed in 2013 for our Ottawa facility. Under the new contract, the plant will become dispatchable for up to 72 MW of capacity. The new contract provides long-term stable earnings for this facility.

Parkeston
During the last quarter of 2015, we executed an extension to our power purchase agreement to supply power to the Kalgoorlie Consolidated Gold Mine from our 55 MW share of the Parkeston power station. The agreement extends the previous contract to October 2026 with options for early termination available to either party beginning in 2021. The contract extension will continue to provide stable cash flow for the business.

Over the last three years, we have nearly doubled the weighted average remaining contractual life of our gas fleet from six years to 12 years.

Human Capital

Engaging our workforce, developing our employees, and minimizing safety incidents are the keys to human capital value creation at TransAlta. The most material impacts an our human capital performance are an engaged workforce and keeping our employees safe.

As at Dec. 31, 2016, we had 2,341 active employees. This number has decreased by two per cent since the previous year, following various restructuring initiatives to reduce costs and increase efficiency. A number of unfilled positions have also been eliminated.

With approximately 53 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns, and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith, and we respect the rights of all employees to participate in collective bargaining.

Organizational Culture and Structure
Our employees are central to our value creation. Our corporate culture is one that has been cultivated throughout our more than 100-year heritage of pioneering innovative ways to safely and responsibly generate reliable and affordable electricity. In 2016 we formalized our core values to help provide strategic clarity for our employees. We want our people to align with and live our core values, which are: innovation, respect, loyalty, accountability, integrity, and safety. TransAlta has a stimulating work environment and we seek to challenge our employees to maximize their potential. We encourage alignment with our values and work ethic, while providing a foundation for leadership, collaboration, community support, growth, and work life balance.

During 2015 we initiated the Powering Performance organizational design program, with the primary objective of accelerating decision-making within our organization. The program has had us transition more fully to a decentralized, business-centric model, with Coal & Mining, Gas & Renewables, Australia, and Energy Marketing defined as our four primary businesses. As part of the design work, we have transferred accountability for shared services to the businesses and removed a layer of management. As part of this process, employees also have clearer accountabilities and authority.

Employee Benefits
TransAlta is an attractive employer in all three countries in which we operate. We provide compensation to our employees at levels that are competitive in relation to their respective location. We strive to be an employer of choice through our total rewards program, which includes various incentive plans designed to align performance with our annual and mid-term targets, as determined annually by the Board.

Also included in compensation are various future benefit plans. We have registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for members whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plans acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The defined benefit plans are funded by the Corporation in accordance with governing regulations. We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65. The supplemental pension plan is an obligation of the Corporation. We are not obligated to fund the supplemental pension plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $73 million to secure the obligations under the supplemental pension plan.

Safety
At TransAlta we operate large and complex facilities. The environments in which we work – including Canadian winters and the Australian outback, often add an additional challenge to keep our employees safe. The safety of our staff, contractors, and visitors is one of the top priorities, if not the top priority, of our social performance. Our safety culture is further embedded into TransAlta culture each year. Every meeting of more than four people starts with a "safety moment," which helps share key safety learnings across our company. Our Operational Integrity program is focused on reducing safety hazards. Our core values include the safety of our people.

In 2016 our IFR was 0.85. IFR is defined as the number of lost-time and medical injuries for every 200,000 hours worked. Our ultimate goal is to achieve zero injury incidents, but annually we seek improvement over the prior year. We have experienced no fatalities during the last three years.

Year ended Dec. 31	**2016**	2015	2014
IFR	**0.85**	0.75	0.86

During 2015, we designed a new total safety management policy as a two-pronged approach. The policy builds on our occupational safety program, Target Zero, which is focused on protecting our workers on site, through means of personal protection equipment, inspections, safety controls, job safety analyses, field-level hazard assessments, and safety communications. The policy is supplemented by our newly launched Operational Integrity program, which is focused on preventing all hazards from equipment, through definition and measurement of safety-critical performance measures and operating limits.

Intellectual Capital

Intellectual capital at TransAlta is another key to our value creation. We have developed innovative solutions to optimize and maximize value from our fleet. We are constantly exploring use of applied or new technologies to find solutions to expand or adapt our fleet in an ever-changing world, which helps protect our shareholder value and maintain delivery of reliable and affordable electricity.

Operations Diagnostic Centre

TransAlta has maintained its Operations Diagnostic Centre ("ODC") since 2008. The ODC monitors coal-fired, gas-fired, and wind-generating assets across Canada, the United States, and Australia. A centralized team of engineers and operations specialists remotely monitors our power plants for emerging equipment reliability and performance issues. ODC staff are trained in the development and use of specialized equipment monitoring software and can apply their experience in power plant operations. If an equipment issue is detected, the ODC notifies plant operations to investigate and remedy the issue before there is an impact to operations. The monitoring, analysis, and diagnostics completed by the ODC are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day plant operations.

Operational Integrity Program

During 2015, we set the foundation for our Operational Integrity program. The program is designed to achieve process and equipment safety through understanding and monitoring of key risks and implementing of mitigation measures. In 2015, we completed our risk assessment at all facilities except Australia and Mining. We have also developed operator checks, maintenance tasks, and proof tests for various safety-critical elements at coal plants. Key performance indicators have been identified and are being integrated in a dashboard for ongoing monitoring. During 2016, we finalized developing the balance of safety-critical maintenance strategies and related engineering standards. We seek to optimize cost and reliability of our assets and maintain or increase their capacity. Our decentralized organization allows the sharing and deployment of technology-specific innovative practices within the respective businesses. Productivity projects are evaluated against criteria that include a two- to three- year financial payback. We also incurred $3 million in 2016 on a productivity improvement blade enhancement technology at our Wolfe Island wind project. This investment is expected to increase the annual energy production of the Wolfe Island wind project by approximately three per cent. In 2017 we are planning to put into place our Total Safety Management System where we integrate our work in Process Safety with our existing Occupational Safety programs. We continue to observe a positive increase in self-reporting and addressing process safety hazards as awareness and new tools are being introduced.

Energy Trading and Marketing

Our energy trading and marketing operations optimize the financial returns of our facilities in real time. The group purchases fuels to feed plants, bids the electricity we generate at our facilities into energy markets, and mitigates the associated risks associated with those purchases and sales. In addition, they buy, sell, schedule, and negotiate all of the electricity transmission for each facility. They do so while applying an overlay of complex, real-time information about weather, facility capacity, transmission congestion, and market pricing. Quantitative analysis, forecasting, mathematical models, and forward curves are key tools used to execute this responsibility. In addition, the application of these skills for proprietary trading allows us to generate positive margins.

Effective Jan. 1, 2016, a new Energy Trading and Risk Management System ("ETRMS") became operational, to further support optimization and trading capabilities, allowing for streamlined data flows, state-of-the-art linkages, and enhanced scalability for key optimization tools. The ETRMS was integrated into our internal control over financial reporting for the year ended Dec. 31, 2016.

Innovation: Applied Technologies

TransAlta has been at the forefront of innovation in the power generation sector since the early 1900s when we developed hydro assets. To add context, these assets were developed at the same time as the automobile. We have been an early adopter of wind technology in Canada and today are the largest wind generator in the country. Today we run a Wind Control Centre, the only one of its kind in Canada, that monitors, to the second, each and every wind turbine we operate across North America. In 2015 we made our first investment in solar technology with the purchase of the Massachusetts solar facilities.

As we move towards becoming the leading clean power company in Canada by 2030 we will continue to seek solutions to innovate. The announcement of our proposed Brazeau hydro expansion, a 600-900 MW pumped hydro expansion, which will double our hydro capacity in Alberta, demonstrates our ability to seek solutions to create value for both our shareholders and society. Hydro is a clean alternative to both coal and gas and has long-term life. We still operate some of our legacy hydro assets from the early 1900s today.

We strive to keep up to date with power technologies that have the potential to redefine power markets today and in the future. Innovation is constantly happening on a more micro scale at TransAlta. For further communication on innovation at TransAlta please visit www.transalta.com/about-us/innovation.

Social and Relationship Capital

Creating shared value for our stakeholders is the key to social and relationship value creation at TransAlta. The most material impacts to our social and relationship performance are public health and safety, anti-competitive behaviour and fostering better relationships and conditions with all stakeholders, but with a key focus on indigenous groups. Each year we strive to do better in each of these areas.

Public Health and Safety
We seek to ensure public health and safety through measures such as restricting physical access to our operating sites and by minimizing our environmental impact. It is our goal to both keep our employees safe and the peoples and the communities in which we operate.

We specifically look to protect against the following risks:
- harm to person(s),
- damage to property,
- increased liability due to negligence, and
- loss of organizational reputation and integrity.

When addressing concerns such as occupiers liability, our Corporate Security team liaises with stakeholders to facilitate appropriate security countermeasures and controls to prevent or reduce the identified risk. For example, in 2016 our Corporate Security term initiated a security/safety signage campaign across the Hydro fleet to elevate the awareness of the safety risks associated with dams. By implementing signage from a safety perspective, Corporate Security and TransAlta also benefited from a security perspective. Signage gave notice of potential physical dangers, but also allows as an organization and landowner to reduce liability and increase safety through notice, awareness, and mitigation of trespassing and vandalism.

We actively monitor air emissions from our coal and gas plants. Our large coal facilities have Continuous Emissions Monitoring Systems ("CEMS") in place, which help us monitor our pollutant emission levels in line with acceptable limits. When we are in breach of regulatory limits we report this to Alberta Environment & Parks and conduct a root cause analysis to understand how we can eliminate future breaches from occurring. In 2016 we had two breaches at our Alberta coal facilities. Both breaches were minor and due to an instrumentation calibration failure at Keephills 3 and an opacity CEMS analyzer failure at the Sundance operations.

Of note, our coal plants currently capture 80 per cent of mercury emissions and the majority of particulate matter emissions. Both have been deemed harmful to human health, which we recognize and work to minimize through capture. The health impact risk from emissions that do reach our environment is minimized due to the location of our plants, which are located away from urban environments. Independent studies conducted by University of Alberta scientist Dr. Warren Kindzierski, using provincial government monitoring data from the past nine years, also show that only approximately 10 per cent or less of all particulate matter in the airshed in the largest urban environment close to our facilities, Edmonton, can be attributed to coal combustion emissions. Chemical "signatures" for emissions pointed to several sources of air quality concern in Edmonton, including local industries, vehicles, and wood-burning fireplaces.

We are currently evaluating the option of converting some of our coal-fired units to natural gas units in 2022 and 2023, which will represent 90 per cent of our coal fleet at that point in time. This action will reduce our GHG emissions by close to 50 per cent. It will also eliminate the majority, if not all, of our mercury emissions and nitrogen oxide emissions from our Alberta coal facilities.

Stakeholder Relations
TransAlta implemented a corporate stakeholder engagement framework in 2016, a streamlined corporate-wide approach to ensure that engagement and relationship-building practices are consistent across TransAlta's locations and types of work. This framework is modelled and closely tied to the stakeholder engagement aspect of ISO 14001, which is an internationally recognized environmental management standard.

In 2016 we introduced our Stakeholder and Aboriginal Relations ("STAR") tracking program. STAR functions as a communication record-keeping tool, which is managed by our Stakeholder and Aboriginal Relations team. This capacity fulfils our requirements for consultation with stakeholders and aboriginal groups alike, and is capable of producing reports (notably, government reports) as proof of engagement and consultation efforts. Built as a SharePoint page, STAR has the capacity to centralize information and grant different levels of access to the information it stores.

Some features of the STAR program include:
- in-house application with no operating cost or fees,
- centralized for the entire company to use,
- different levels of accessibility (privileges),
- can store email conversations, documents, and voice-mail messages related to any project, event, or issue; and use them in reports, and
- produces an array of statistical reports showing frequencies and volumes of engagement based on project, stakeholder, stakeholder group, issue, or keywords.

The Board believes that it is important to have constructive engagement with its shareholders and other stakeholders and has established means for the shareholders of the Company and other stakeholders to communicate with the Board through the use of a confidential Ethics Helpline or by writing directly to the Board. The contact information for communicating with the Board is published in Whistleblower section of this MD&A. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. In addition, the Board has adopted an annual non-binding advisory vote on the Company's approach to executive compensation. The Company is committed to ensuring continued good relations and communications with its shareholders and other stakeholders and will continue to evaluate its practices in light of any new governance initiatives or developments.

Aboriginal Relations
The focus of our efforts in this area is to establish solid relationships with indigenous and Métis communities, recognizing and respecting their rights and focusing on engaging them at the earliest stages of any project or development. Specifically, our aboriginal relations team continues to develop and enhance aboriginal relations in areas of employment, economic development, community engagement, and investment. Since 2014, we have achieved the Canadian Council for Aboriginal Business's silver-level Progressive Aboriginal Relations certification. As noted above, in 2016 we introduced our STAR tracking program, which functions a communication record-keeping and engagement measurement tool.

Local Communities
We provide public benefit through reliable, cost-efficient power and related outputs or services. With the phase-out of coal on the horizon, we seek to secure favourable outcomes for our workers and the communities surrounding our plants. Our proposed coal-to-gas conversions provide the opportunity to maintain some jobs during conversions, to support sector jobs, and to redeploy some of our workforce in the plants or toward renewables growth. Electricity and energy have always been at the heart of the economy in Alberta, and any changes in the industry must therefore support our communities. Conversion will also help keep municipal, provincial, and federal tax revenues supporting these communities. TransAlta advocates for sufficiently long timelines for transition, support for facility redevelopment, funds for retraining, and economic diversification.

Community
During 2016, TransAlta contributed $2.5 million in donations and sponsorships (2015 - $3.5 million).

On July 30, 2015, we announced that we were moving ahead with plans to invest US$55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The US$55 million community investment is part of the TransAlta Energy Transition Bill, passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders, and TransAlta to transition away from coal in Washington State, closing the Centralia facility's two units, one in 2020 and the other in 2025. Although we did not secure additional long-term contracts totalling 500 MW as planned in the original agreement as a condition of the investment, we are following through on our funding pledge and securing mutual benefits agreed with the State for orderly transition.

Competitive Behaviour
On July 27, 2015, the AUC issued a ruling that found, among other things, that our actions in relation to four outage events at our coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated PPA buyers and manipulated market prices away from a competitive market outcome.

On Sept. 30, 2015, TransAlta and the Alberta Market Surveillance Administrator ("MSA") reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which was in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the agreement, we agreed to pay a total amount of $56 million that included approximately $27 million as a repayment of economic benefits, approximately $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million was paid in the fourth quarter of 2015, and $25 million was paid in the fourth quarter of 2016.

When we became aware that the market rules governing forced outages were in dispute, we changed our compliance procedures, and the actions that led to this case have not been repeated. In order to rebuild trust, we asked a national law firm with expertise in electricity markets, and a national accounting firm, to complete independent third-party reviews of our then current compliance procedures around forced outages. We also asked them to review our trading compliance program to ensure that our current practices met the company's legal and ethical obligations and the high expectations of our customers and stakeholders, the results of which were made public during the first half of 2016.

The national law firm assessment concluded that:
- outage practices are consistent with the law in Alberta, and
- senior management has demonstrated a strong commitment to compliance.

Recommendations were provided to formalize the outage practices and procedures and related document management, and to incorporate the procedures into the existing TransAlta Compliance programs in terms of training, investigation procedures and annual reviews.

Using a 10-point compliance effectiveness review framework, the national accounting firm's assessment of TransAlta's Energy Trading Compliance Program concluded that:
- from a program design perspective, TransAlta's program contains each of the 10 components of an effective compliance program, and includes the key elements required and normally seen at industry peers, and
- in terms of operational effectiveness, TransAlta's program meets or exceeds current industry practice in each of the 10 components.

Recommendations were provided in 5 of the 10 areas, for increasing cross functional communications, cross-training of compliance staff, scheduling of training components more frequently throughout a year, formalizing documentation of monitoring tools and performance review assessments for compliance.

TransAlta has accepted all of the recommendations in both reports.

Natural Capital
All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind, hydro, and solar, we also believe that natural gas will continue to play an important role in meeting energy needs as part of this transition. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost electricity. Currently the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (pollutants, metals), and energy use. Material impacts that we manage and track include our environmental management systems, environmental incidents and spills, land use, water usage, and waste management.

In the jurisdictions in which we operate, legislators have proposed and enacted regulations to discontinue, over time, the use of the technologies our coal-fuelled plants currently utilize. Our gas and coal facilities can also incur costs in relation to their carbon emissions, depending on the jurisdiction in which the facility is located. Our contracted facilities can generally recover those costs from the customer. Conversely, our renewable generation facilities are generally able to realize value from their environmental attributes. We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

Reducing the environmental impact of our activities has a benefit not only to our operations and financial results, but also to the communities in which we operate. We expect that increased scrutiny will be placed on environmental emissions and compliance, and therefore we have a proactive approach to minimizing risks to our results. Our Board provides oversight to our environmental management programs and emission reduction initiatives to ensure

continued compliance with environmental regulations.

Our environmental initiatives include:

- Renewable power growth and offsets portfolio: Over the last 10 years, we have added approximately 1,300 MW in renewable energy capacity. From our Alberta wind fleet, 360 MW of capacity generates offsets that can be applied against GHG emissions in Alberta. Annual revenue generation from these offsets is in the range of $10 million to $15 million.
- Environmental controls and efficiency: We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Canadian Coal operations in 2010 in order to meet Alberta's 70 per cent reduction objectives, and voluntarily at our U.S. coal-fired plant in 2012. In 2016 we achieved an 80 per cent capture rate of mercury at all coal facilities. Our Keephills 3 and Genesee 3 plants use supercritical combustion technology to maximize thermal efficiency, as well as sulphur dioxide ("SO_2") capture and low oxides of nitrogen ("NOx") combustion technology. Uprate or energy- efficiency projects completed at our Keephills and Sundance plants, including a 15 MW uprate finalized in 2015 at Sundance 3, have improved the energy and emissions efficiency of those units.
- Planning: With respect to environmental rules (as detailed in the following Regional Regulation and Compliance subsection), we investigate the cost effectiveness of multiple technological solutions and various operating models in order to prepare appropriate work scopes. In 2016 we announced our proposed coal to natural gas conversions and support for the Government of Alberta's renewable electricity plans.
- Policy participation: We are active in policy discussions at a variety of levels of government and with industry participants. Where capacity retirements are being mandated, we advocate minimizing the capital requirements of incremental regulation, to allow reinvestment in lower-intensity sources during the transition phase. In Washington State, the retirement of our Centralia coal plant was established through a multi-stakeholder agreement. In 2016 we entered into the MOU with the Government of Alberta, which entails co-operation and collaboration to enable the conversion of coal-fired generation to gas-fired generation.

In addition to these initiatives, we maintain similar procedures for environmental incidents as we do for safety, with tracking, analyzing, and active management to eliminate occurrence, and ongoing support from our Operational Integrity Program. With respect to biodiversity management, we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities and closely monitor the air, land, and water in these areas to identify and curtail potential impacts.

Environmental Performance

All of our 69 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely mimic the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for 17 years, and our systems and knowledge of management systems are therefore mature. In 2016 we moved to no longer certify our Alberta coal plants as ISO 14001, but the plants continue to run best practice EMS, as do 97 per cent of our facilities. Only two of our facilities do not closely track ISO 14001, which is due to commercial arrangements (we are not the primary operator), but these facilities still have EMS in place.

Environmental Incidents and Spills

We recorded 16 reportable environmental incidents in 2016 (2015 - 12 incidents), which was above our target of 13. None of these incidents resulted in a material environmental impact. Our Gas & Renewables fleet recorded only three incidents in 2016, a record year. The remainder of our 13 environmental incidents occurred at our Alberta Coal business unit. Incident types included spills, which were highly recoverable, air emission exceedances or instrument failures, wastewater sampling errors, effluent releases, water blowdown exceedances, and process safety incidents. We will continue to target improvement in 2017 with a specific focus on Alberta Coal. Our corporate-wide 2017 target is 11 or fewer incidents. We also continue to track and manage all non-reportable (minor) environmental incidents, which helps us identify what leads to an incident. Understanding the root cause of incidents helps with incident prevention planning and education.

Typical spills at TransAlta are hydrocarbon spills, which happen in low environmental impact areas and are almost always contained and recovered. It is extremely rare that we experience large spills with impact on the environment. Spills that do occur that we must report are typically just above acceptable regulatory spill limits and these are always addressed with a critical time factor. The volume of spills in 2016 was 61 m^3 (2015 - 19 m^3), of which 78 per cent was recovered (2015 - 99 per cent recovered). The increase is attributable to three large spills, two at our Sundance coal operations and one at Mt Keith in southwestern Australia. All three incidents were contained at our sites and were reported to the appropriate bodies.

Energy Use

TransAlta uses energy in a number of different ways. We burn coal, gas, and diesel to generate electricity. We harness the kinetic energy of water and wind to generate electricity. We also utilize the sunshine to generate electricity. In addition to combustion of fuel sources we also track combustion of fuel in the vehicles we use and energy use in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies.

The following are our millions of gigajoules of energy use. On a comparable basis, our energy use has declined over the last three years as a result of lower generation from our coal-generating assets.

Year ended Dec. 31	**2016**	2015[1]	2014
Coal	**469.1**	483.4	529.7
Gas and Renewables	**59.2**	58.7	54.3
Corporate	**0.1**	0.1	0.1
Total energy use	**528.4**	542.2	584.1

(1) Gas & Renewable 2015 volumes were restated due to a diesel volume reporting error at our Solomon facility.

Greenhouse Gas Emissions

In 2016, we estimate that 30.7 million tonnes of GHGs with an intensity of 0.84 tonnes per MWh (2015 - 32.2 million tonnes of GHGs with an intensity of 0.87 tonnes per MWh) were emitted as a result of normal operating activities.[1] Our GHG emissions decreased slightly in 2016, primarily as a result of lower production from coal plants. Other decreases in emissions of the Canadian Gas segment are attributable to the transfer of operational control of the Poplar Creek facility to our customer in September 2015, conversion of the Ottawa plant to a peaking facility in 2013, and conversion of the Solomon plant in Australia to burn natural gas instead of diesel.

The following are our GHG emissions in million tonnes CO_2:

Year ended Dec. 31	**2016**	2015	2014
Coal	**27.7**	29.2	32.3
Gas and renewables	**3.0**	3.0	2.7
Total GHG emissions	**30.7**	32.2	35.0

Our continued investment in growth from renewable power generation further supports the decrease in emissions intensity observed in 2016. We believe in proactive measurement and disclosure of air emissions.

In 2016, TransAlta improved its scoring on the Carbon Disclosure Project Climate Change report to a B, our highest integrated score yet. We were also highlighted by Chartered Professional Accountants of Canada as the only company in Canada, out of 75 companies, that reports on climate change across all levels of disclosure: the annual information form, this MD&A, and our information circular.

Refer to the Climate Change section of this MD&A for further information.

Air Emissions

In 2016 air emissions were down compared with 2015. Air emissions decreased slightly in line with reduction in coal power generation.

Year ended Dec. 31	**2016**	2015	2014
Sulphur dioxide (tonnes)	**39,600**	41,800	47,600
Nitrogen oxide (tonnes)	**48,400**	48,000	52,900
Particulate matter (tonnes)	**4,900**	4,900	5,200
Mercury (kilograms)	**130**	170	220

Our continued investment in growth from renewable power generation further supports the decrease in emissions intensity observed in 2016. We believe in proactive measurement and disclosure of air emissions.

(1) 2016 data are estimates based on best available data at the time of report production. GHGs include water vapour, carbon dioxide ("CO_2"), methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.

Emissions intensity data has been aligned with the 'Setting Organizational Boundaries: Operational Control' methodology set out in The GHG Protocol: A Corporate Accounting and Reporting Standard. As per the methodology, TransAlta reports emissions on an operation control basis, hence we report 100 per cent of emissions at facilities in which we are the operator. Emissions intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership.

Water

Our principal water uses are for cooling and steam generation in coal and gas plants, and for hydro power production. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2016 we withdrew 247 million m^3 and returned approximately 188 million m^3 back to its source. Water is withdrawn primarily from rivers where we hold permits to withdraw water and adhere to regulations on water quality. We return or discharge approximately 70 per cent of water back to the source, meeting the regulatory quality levels that exist in the various locations in which we operate. The difference between withdraw and discharge, representing consumption, is largely due to evaporation loss.

The following represents our total water consumption (million m^3) over the last three years:

Year ended Dec. 31	**2016**	2015	2014
Water from environment	**247**	272	243
Water to environment	**188**	198	172
Total water consumption	**59**	74	71

Our areas of higher water risk are situated east of Perth in our simple-cycle gas plants in Western Australia and in our Southern Alberta hydro operations.

We monitor and manage water risk in our operating areas east of Perth.

In Southern Alberta, following the flood of 2013, our hydro facilities are being used for an increased water management role than they have played in the past. During 2016, we signed a five-year agreement with the Government of Alberta to manage water on the Bow River at our Ghost reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis Lakes System (which includes Interlakes, Pocaterra and Barrier), for drought mitigation efforts.

Land Use

The largest land use associated with our operations is for surface mining of coal. Of the three mines we have operated, Whitewood is completely reclaimed and the land certification process is ongoing. Centralia is in the reclamation phase, and Highvale is actively mined with ongoing reclamation. Our reclamation plans are set out on a lifecycle basis and include contouring disturbed areas, re-establishing of drainage, replacing topsoil and subsoil, re-vegetation, and land management. Our mining practice incorporates progressive reclamation where the final end use of the land is considered at all stages of planning and development.

In 2016, we reclaimed 39 acres (16 hectares) at our Highvale mine, which was below our target of 74 acres (30 hectares) due to the impact of warm weather on soils in the winter, as cold temperatures facilitate reclamation work and the spreading of topsoil. The Centralia mine is no longer actively used for coal operations, but reclamation activity is ongoing. In 2016 we reclaimed 38 hectares of land.

Also in 2015, we donated 64 acres of land to the Alberta Wildlife Trust Fund. The land includes an area that was once a mine settling pond and is a site of ecological significance. The donation aligns with our objectives for community participation and stakeholder engagement.

Waste

Our operating teams work to minimize waste and maximize recoverable value from waste. Over the years, we have invested in equipment to capture byproducts from the combustion of coal, such as fly ash, bottom ash, gypsum, and cenospheres, for subsequent sale. These non-hazardous materials add value to products like cement and asphalt, wallboard, paints, and plastics. Byproduct sales and associated annual revenue generation typically ranges from $25 million to $35 million.

Coal Transition

Our coal transition, whether it is executing on our coal-to-gas conversion plans or completing a full phase-out by 2030, will vastly improve our environmental performance. Energy use, GHG, air emissions, waste generation, and water usage will all significantly decline. A conversion of coal-fired power generation to gas-fired generation is expected to eliminate all mercury emissions and the majority of nitrogen oxide emissions.

Climate Change

Governance

TransAlta's Governance and Environment Committee ("GEC") is a Board-appointed committee that reports directly to the Board of Directors to help fulfil oversight responsibility with respect to environment, health, and safety. In conjunction, the GEC and Board hold the highest levels of oversight in regards to TransAlta's climate change policy and sustainability initiatives.

Strategy

Climate change related risks are monitored through our company-wide risk management processes and actively managed. Identified climate change risks and opportunities are also reviewed by our management team through our Governance and Environment Committee. We attribute regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks pertaining to uncertainty in the carbon market and as a safeguard to anticipate future impacts of regulatory changes on facilities. It is also a method of modelling for future electricity prices and to analyze the viability of acquisitions. Identified climate change risks or opportunities and carbon pricing are recognized in the annual TransAlta long-and-medium range forecasting processes. Regulatory risk/compliance (coal electricity generation), physical risks (hydro and drought/floods), and monetary opportunities (gas and renewable electricity generation) are the main drivers of integration into business strategy.

Aligned with our business strategy is our climate change strategy, which is implemented and managed on a corporate-wide business unit level, consisting of four main areas of focus:

- § Energy-efficiency improvements,
- § Development of emissions offsets portfolios to achieve emissions reductions at competitive costs,
- § Development of clean combustion technologies,
- § Growth of our renewables portfolio as an increasing component of our total generation portfolio.

We seek investment in climate change related mitigation solutions where we can maximize value creation for our shareholders, local communities, and the environment. Anticipated conversion of our large coal fleet to gas-fired generation highlights this approach, which will allow us to run our assets longer than the federally mandated coal retirement schedule. Our anticipated actions maximize value for our shareholders, ensure low-cost and reliable power for Albertans, and reduce the environmental impact from coal-fired generation.

Our investment and growth in renewable energy is highlighted by our diverse portfolio of renewable energy generating assets. We currently operate and are invested in over 2,200 MW of hydro, wind, and solar power. We are the largest producer of wind power in Canada and the largest producer of hydro in Alberta. Production from renewable energy in 2016 resulted in avoidance of over 3.1 million tonnes of CO_2e, which is equivalent to removing over 730,000 vehicles from North American roads. For further details on governance and risk, see our Governance and Risk Management section of this MD&A.

Targets

We recognize climate change risk and the goal set out in the 2015 Paris Agreement to prevent two degrees Celsius of global warming above pre-industrial levels. Our GHG reduction targets have been established to align with the UN Sustainable Development Goals, specifically Goal 13, which calls for "urgent action to combat climate change and its impacts." Our 2030 GHG reduction target is set based on climate-based science and the goal of preventing two degrees Celsius of global warming. This target is approved by the Science Based Targets initiative, which is a partnership between the Carbon Disclosure Project, UN Global Compact, World Resources Institute and World Wildlife Fund, which helps companies determine how much they must cut emissions to

prevent the worst impacts of climate change.

Our GHG reduction targets are as follows:

1. Our goal, in line with a commitment to the UN Sustainable Development Goals ("SDGs"), is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels.
2. Our goal, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming, is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels.

Regional Regulation and Compliance

Carbon issues and related legislation will continue to have an impact on our business. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

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

Canadian Federal Government

In November 2016, the Canadian federal government announced that coal-fired generation would be phased out by 2030, following a similar commitment by the Alberta provincial government in November 2015. These two decisions changed the coal plant closure requirements, which had previously been guided by the federal regulations that became effective on July 1, 2015 which provided for up to 50 years of life for coal units. According to the new shut-down requirements, the Corporation's older coal units (which retire prior to 2030) will be guided by the 50-year life rule, while newer units (which were previously scheduled to retire post-2030) will face the new 2030 shutdown date. In November 2016, the Corporation signed an OCA with the Alberta Government that confirmed the 2030 shutdown commitment for the impacted units.

On Nov. 21, 2016, the Canadian federal government announced that the Department of Environment and Climate Change will be developing regulations for gas-fired generation. The announcement confirmed plans to include specific rules for coal-to-gas converted units, including a proposed 15-year life and a separate emissions intensity standard. The Canadian federal government will conduct consultations on the proposed regulation in the first two quarters of 2017. Finalized regulations are currently expected by the end of 2018.

On Oct. 3, 2016, the Canadian federal government announced its intention to implement a national price on GHG emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022, or a comparable reduction in GHGs under a cap-and-trade program. The application of the price would be co-ordinated with provincial jurisdictions. We do not yet know how such a price mechanism will affect our operations.

Alberta

On Nov. 22, 2015, the Government of Alberta announced through the Climate Leadership Plan its intent, among other things, to phase out emissions from coal-fired generation by 2030, replace two-thirds of the retiring coal-fired generation with renewable generation, and impose a new carbon price of $30 per tonne of CO_2 emissions based on an industry-wide performance standard. On March 16, 2016, the Government of Alberta announced the appointment of a Coal Phase-out Facilitator to work with coal-fired electricity generators, the Alberta Electric System Operator ("AESO"), and the Government of Alberta to develop options to phase out emissions from coal-fired generation by 2030. The Coal Phase-out Facilitator was tasked with presenting options to the Government of Alberta that would strive to maintain the reliability of Alberta's electricity grid, maintain stability of prices for consumers, and avoid unnecessarily stranding capital.

In March 2016, Alberta began development of its renewable energy procurement process design for the AESO to procure a first block of renewable generation projects to be in-service by mid-2019. On Sept. 14, 2016, the Government of Alberta reconfirmed its commitment to achieve 30 per cent renewables in Alberta's electricity energy mix by 2030.

On May 24, 2016, the Government of Alberta passed the *Climate Leadership Implementation Act* which establishes the carbon tax framework for its application to fuels. It is expected that additional regulations will be developed governing the treatment of large industrial emitters. The Climate Leadership Plan will be implemented for the electricity sector on January 1, 2018.

On Nov. 24, 2016, we announced that we had entered into the OCA, which provides for transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. Under the terms of the OCA, the Corporation will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. For further details, refer to the Highlights section of this MD&A.

Additionally, we announced that we had reached an understanding set out in the MOU to collaborate and co-operate with the Government of Alberta in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the Province of Alberta.

Since 2007, we have incurred costs as a result of GHG legislation in Alberta. On June 29, 2015, the Alberta government announced an increase to its provincial Specified Gas Emitters Regulation:

§ On Jan. 1, 2016, an increase in the GHG reduction obligation for large emitters from 12 per cent to 15 per cent of emissions, with the compliance price of the technology fund rising from $15 per tonne to $20 per tonne.

§ On Jan. 1, 2017, a further increase to a 20 per cent reduction requirement and a $30 per tonne compliance price.

Our exposure to increased costs as a result of environmental legislation in Alberta is mitigated to some extent through change-in-law provisions in our PPAs that allow us the opportunity to recover capital and operating compliance costs from our PPA customers. The GHG offsets created by our Alberta wind facilities are expected to increase in value through 2017, as GHG emitters can use them as compliance instruments in place of contributing to the technology fund. As part of the Climate Leadership Plan, the government has stated its intention to establish a new system of obligations and allowances, benchmarked against highly efficient gas generation, beginning in 2018. The initial compliance price would be set at $30 per tonne, escalating annually.

In Alberta there are additional requirements for coal-fired generation units to implement additional air emission controls for oxides of NOx and SO_2 once the units reach the end of their respective PPAs, in most cases in 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance ("CASA"). The release of the federal regulations in 2012 adopted by the Government of Canada and the Government of Alberta, and the accelerated coal-fired generation retirement schedule, creates a potential misalignment between the CASA air pollutant requirements and schedules, and the retirement schedules for the coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulate emissions, something which has been identified as a matter yet to be addressed in the MOU.

The Government of Alberta's Renewable Electricity Program is intended to encourage the development of 5,000 MW of new renewable electricity capacity by 2030. The AESO is currently soliciting interest in the first competitive procurement for 400 MW under the program. Proponents must submit an expression of interest by late March 2017. The process will be followed by a request for qualification in late April 2017, request for proposal in mid-September 2017 and successful proponents announced in December 2017. Eligible projects must be 5 MW or larger and can be hydro, wind, solar, and certain biomass. The successful projects will be awarded a Renewable Electricity Supply Agreements that utilizes an indexed renewable energy credit or contract for difference mechanism that will fix the price to the proponent over 20 years. The contracts are expected to require the facility to be operational by 2019.

The Government of Alberta has tasked the AESO with transitioning Alberta's energy-only market to a capacity market structure. The capacity market will help to ensure that there is sufficient supply adequacy as over 6,000 MW of coal generation retires by 2030. The new market structure is expected to reduce the reliance on scarcity pricing, which drives energy price volatility and the price signal for new investment, and compensate resource owners with monthly capacity payments for making their capacity available in the energy and ancillary services market. The AESO plans to engage stakeholders in determining the design and implementation of the capacity market over 2017 and 2018 and conduct the first auction in 2019 with a contract delivery year targeted for 2021. The AESO has suggested they will need new capacity in 2021.

Pacific Northwest
On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the state, which is where our U.S. Coal plant is located. Included in this program are a cap-and-trade plan and a low-carbon fuels standard. The proposed emissions cap will become more stringent over time, providing emitters time to transition their operations.

On Aug. 3, 2015, former U.S. President Obama announced the Clean Power Plan. The plan sets GHG emission standards for new fossil-fuel-based power plants and emission limits for individual states. States will have the option of interpreting their limits in mass-based (tons) or rate-based (pounds per MWh) terms. The plan is intended to achieve an overall reduction in GHG emissions of 32 per cent from 2005 levels by 2030. It will be implemented in two stages: 2022 to 2029, and 2030 and beyond.

On Feb. 9, 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending consideration as to whether the regulations are lawful. It is not clear yet how this may affect the future of the Clean Power Plan. As a result of our 2011 agreement for coal transition with the State of Washington, we do not expect the proposed regulations to significantly affect our U.S. operations.

These additional regulations for existing power plants are not expected to significantly affect our U.S. operations. TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State's climate change program. We currently believe that there will be no additional GHG regulatory burden on U.S. Coal given these commitments. The related TransAlta Energy Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation.

Ontario
On Feb. 25, 2016, Ontario released draft regulations for its GHG cap-and-trade program that were finalized on May 19, 2016. The regulations became effective Jan. 1, 2017, and will apply to all fossil fuels used for electricity generation. The majority of our gas-fired generation in Ontario will not be significantly impacted by virtue of change-in-law provisions within existing power purchase agreements.

Australia
In Australia, the Senate recently passed amendments to the country's Renewable Energy Target Scheme. The scheme was initially introduced in 2001 with three objectives: to establish a mandatory renewable energy target to be achieved in 2020; to provide incentives for large-scale renewable energy generators in the form of one large-scale generation certificate earned for each MWh of generation; and to require retailers and wholesale industrial customers to purchase a specified volume of their electricity from large-scale renewable-sourced electricity or incur a penalty of AUD$65/MWh on any shortfall. The amendments reduced the annual targets for large-scale renewable sourced electricity down from 41,000 GWh in 2020 to 33,000 GWh in 2020, held constant at this level until 2030. It is estimated that this will require an additional 5,000-6,000 MW of new renewables capacity to be installed to add to the slightly more than 4,000 MW already operating. Since our Australian assets are fully contracted it is not expected that these amendments will have a significant impact on our operations.

Weather
Abnormal weather events can impact our operations and give rise to risks. In addition, normal year-over-year variations in wind, solar, water, and temperatures give rise to various levels of volume risk depending on the input fuel of each facility; events outside the design parameters of our facilities give rise to equipment risk; and fluctuations in temperatures can cause commodity price risk through impact on customer demand for heating or cooling. Refer to

the Governance and Risk Management section of this MD&A for further discussion of each risk and our related management strategy.

During the past three years, some deviations from expected weather patterns have negatively impacted our annual financial results:

- the Southern Alberta flood of 2013 disrupted our hydro operations and caused us to invest in substantial repair work. Our losses have been largely covered through insurance,
- warm weather in Alberta in 2015 increased derates at our coal facilities due to its impact on the Sundance cooling ponds. These cooling ponds are susceptible to warm weather; however, we anticipate that decreased coal production and the retirement of Sundance Units 1 and 2 in the medium term will reduce the stress from such occurrence, and
- our Alberta mine was susceptible to significant rain starting in August of 2016, which resulted in several weeks of flooding and impacted our coal deliveries. We focused on improving drainage infrastructure and use of stockpiles to mitigate future risks.

Over the same period, other deviations have positively impacted our financial results, such as the cold temperatures in Eastern North America in the winter of 2014 that caused market volatility and benefitted our Energy Marketing Group.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of our monitoring controls, long-range forecasts are prepared for each Cash Generating Unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide a criteria to evaluate adverse changes in operations. When indicators of impairment are present, we estimate a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets extending to the last planned asset retirement in 2073.

In 2016, we concluded that an indicator of possible impairment existed with respect to our U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section III below.

During 2016, uncertainty continued to exist within the province of Alberta regarding the government's previously announced Climate Leadership Plan and the future design parameters of the electricity market. Additionally, economic conditions, while more stable than in 2014 and 2015, contributed to continued over-supply conditions and depressed market prices. We assessed whether these factors presented an indicator of impairment for our Alberta Merchant CGU, and in consideration of the composition of this CGU and events arising during the latter part of 2016, which are more fully discussed below in I, determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, we did not perform an in-depth impairment analysis, but sensitivities associated with these factors were performed to confirm the continued existence of an adequate excess of estimated recoverable amount over net book value.

There was one impairment charge of $28 million (2015 - $2 million reversal) made during the year ended Dec. 31, 2016 as a result of the sale of our 51 per cent interest in the Wintering Hills merchant wind facility as discussed below in II.

I. Alberta Merchant CGU

In 2015, the Government of Alberta announced its Climate Leadership Plan ("CLP"), which broadly called for the phase-out of coal-generated electricity by 2030, and proposed the imposition of additional compliance obligations for GHG emissions in the province. In 2016, the Government of Alberta refined its approach to GHG by instituting a levy on carbon emissions in excess of defined limits, amounting to $20 per tonne in 2017 and $30 per tonne in 2018. At the federal level, the Canadian government announced its intention to implement a national price on GHG emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022.

On November 24, 2016, we entered into the OCA with the Government of Alberta to receive annual cash payments of approximately $37.4 million, net to us in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, we entered into an MOU on Nov. 24, 2016, with the purpose of collaborating and co-operating to advance objectives of the Alberta CLP. Specifically, the parties collaborated on initiatives that included:

- a move toward a capacity market, commencing 2021, compared to the current energy-only market. Under a capacity market, generators are compensated for their available capacity;
- development of a policy and to facilitate the economic conversion of some coal-fired generation to natural gas-fired generation in Alberta, including securing regulatory co-operation from the federal government; and
- development of supportive and enabling policy, including policy that addresses the value of carbon reductions in the generation of electricity from existing wind and hydro generation, the development of effective supporting mechanisms to ensure that existing renewables generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Government of Alberta and the Corporation and does not impose any obligations on, or constrain the discretion and authority of the Government of Alberta. The announcement of the intention to move to a capacity market is expected to impact the Alberta market mechanisms. The Government of Alberta has not provided further detail on the market rules or construct. The introduction of a capacity market to replace Alberta's current market structure could impact our determination of the Alberta Merchant CGU; however, there is not currently sufficient information from the Government of Alberta to determine if a change is required. We have not modified its previous conclusions on the determination of the Alberta Merchant CGU.

During the year, we monitored the potential impacts of the CLP and other announcements on the Alberta CGU. A sensitivity analysis on these estimates to assess potential impacts of the Alberta and federal government policies on the carbon levy and GHG emissions, as well as the impacts of the OCA and MOU. The analysis of the Alberta Merchant CGU, with its large merchant renewable fleet, resulted in no impairment in 2016.

II. Wintering Hills

On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. In connection with this sale, the Wintering Hills assets were accounted for as held for sale at December 31, 2016. As required, we assessed the assets for impairment prior

to classifying them as held for sale. Accordingly, we have recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal.

III. U.S. Coal

We considered possible impairment at the U.S. Coal CGU, and again found that the fair value less costs to sell approximates the current carrying amount. We estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing our long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$22.68 to 45.65 per MWh
On-highway diesel fuel on coal shipments	US$1.69 to 2.09 per gallon
Discount rates	5.4 to 5.7 per cent

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

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

Centralia Gas

During 2014 we sold a portion of the assets of the Centralia gas facility to external counterparties and transferred other assets to other TransAlta facilities. The plant had been fully impaired and idled since 2010. As a result of the transaction, we recognized impairment reversals of $5 million and the plant's generating capacity has been removed from TransAlta's total owned capacity. In 2015, we reversed $2 million of previously impaired change as a result of additional recoveries. No further reversals or impairments were recorded in 2016.

Other Significant and Subsequent Events

Alberta Off-Coal Agreement

On Nov. 24, 2016, we announced that we entered into the OCA with the Government of Alberta on transition payments in exchange for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, we will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions in 2030. Other conditions include maintaining prescribed spending on investment and investment-related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), and maintaining spending on programs and initiatives to support the communities surrounding the plants, and the employees of the Corporation negatively impacted by the phase-out of coal generation and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. We claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, we announced that the independent arbitration panel confirmed our claim for force majeure relief. Accordingly, we reversed a provision of approximately $94 million. The buyer and the Balancing Pool are seeking to appeal or set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. We oppose these steps and believe they are without merit.

Memorandum of Understanding with the Government

In November 2016, we additionally reached an understanding with the Government of Alberta pursuant to an MOU to collaborate and co-operate in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the province of Alberta. Specifically, the parties undertook to collaborate on, among other things:

- § work to ensure existing incumbents and new electricity generation are able to effectively participate in capacity payment auctions to be established as part of the development of a capacity market,
- § development of a policy environment to facilitate the economic and environmentally responsible conversion of some coal-fired generation to natural gas-fired generation in Alberta, including securing regulatory cooperation from the federal government, and
- § development of supportive and enabling policy, including policy that addresses the value of carbon reductions in the generation of electricity from existing wind and hydro generation, the development of effective supporting mechanisms to ensure that existing renewables generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Government of Alberta and the Corporation and does not impose any obligations on, or constrain the discretion and authority of, the Government of Alberta.

Mississauga Cogeneration Facility New Contract

On Dec. 22, 2016, we announced that we had signed a Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") with the IESO for

our Mississauga cogeneration facility (the “Mississauga Facility”). The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, we agreed to terminate effective Dec. 31, 2016, the Facility’s pre-existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018.

The NUG Contract provides us stable monthly payments until Dec. 31, 2018, totalling approximately $209 million, reduced operational costs, and the ability to maintain operational flexibility to pursue opportunities for the Mississauga Facility to meet power market needs in northeastern Ontario.

As a result of the NUG Contract, we recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling $15 million. We also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. We released and recognized in earnings unrealized pre-tax losses of net $14 million from Accumulated Other Comprehensive Income (“AOCI”) due to cash flow hedges de-designated for accounting purposes. The cash flow hedges were in respect of future gas purchases denominated in US dollars expected to occur between 2017 and 2018. In the fourth quarter of 2016, the forecasted gas consumption was no longer expected to occur, which resulted in the cumulative loss on the hedging instruments being released from AOCI and recognized in earnings.

Investment and Acquisition by TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility
On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation’s Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Québec. The transaction was originally announced on Nov. 23, 2015.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30 and December 31, and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of $13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation through issuance of common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery. On Jan. 6, 2016, TransAlta Renewables declared a dividend increase of 5 per cent.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation’s subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million through the issuance of a non-interest bearing loan payable to the Corporation.

Wintering Hills Sale
On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. Proceeds from the sale will be used for general corporate purposes, including reducing our debt and funding future renewables growth. The sale closed March 1, 2017. We acquired the interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with our Poplar Creek cogeneration facility. As at Dec. 31, 2016, the assets are classified as held for sale, and were measured at the lower of carrying amount and fair value less costs to sell, resulting in an impairment charge of $28 million, included in the Wind and Solar segment. This arrangement provides us with near-term liquidity and increases our financial flexibility to pay down debt maturities.

Preferred Share Exchange
On Feb. 10, 2017, we announced that we would not proceed with the transaction previously announced Dec. 19, 2016 pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares.

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2016, to Dec. 31, 2015:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	251	Timing of receipts and payments, and non-recourse bond offerings
Trade and other receivables	136	Timing of customer receipts and seasonality of revenue, and current Mississauga facility recontracting receivable ($91 million)
Assets held for sale	61	Transfer of Wintering Hills wind facility from PP&E
Finance lease receivables (long term)	(56)	Unfavourable changes in foreign exchange rates ($12 million) and scheduled receipts ($56 million), partially offset by an increase due to completion of gas conversion work at the Solomon gas plant ($14 million)

Property, plant, and equipment, net	(349)	Depreciation for the period ($607 million), unfavourable changes in foreign exchange rates ($46 million), retirement of assets ($21 million), partially offset by additions ($358 million), revisions to decommissioning and restoration costs ($71 million), and transfer of Wintering Hills to assets held for sale ($61 million)
Intangible assets	(14)	Amortization ($38 million), partially offset by additions ($24 million)
Deferred income tax assets	(18)	Decreases in deductible temporary differences
Risk management assets (current and long term)	(61)	Unfavourable changes in foreign exchange rates and contract settlements, partially offset by favourable market price movements
Other assets	109	Mississauga facility recontracting long term receivable ($116 million)
Other	(10)	
Total decrease in assets	**49**	

Liabilities and equity	**Increase/ (decrease)**	**Primary factors explaining change**
Accounts payable and accrued liabilities	79	Timing of payments and accruals
Credit facilities, long term debt, and finance lease obligations (including current portion)	(134)	Credit facility repayment ($315 million), repayment of long term debt ($88 million), and favourable effects of changes in foreign exchange rates ($67 million), partially offset by bond issuances ($362 million)
Decommissioning and other provisions (current and long term)	(55)	Keephills 1 provision reversal ($94 million) and liabilities settled ($59 million), partially offset by a decrease in risk-adjusted discount rates ($44 million)
Defined benefit obligation and other long term liabilities	(18)	Amortization of deferred revenue ($7 million) and actuarial gains ($8 million)
Deferred income tax liabilities	65	Mississauga recontracting and increase in taxable temporary differences
Risk management liabilities (current and long term)	(155)	Favourable market price movements and contract settlements
Equity attributable to shareholders	150	Net earnings ($169 million), issuance of common shares ($19 million), gains on cash flow hedges ($106 million), and changes in non-controlling interests in TransAlta Renewables ($26 million), partially offset by net losses on translating net assets of foreign operations ($53 million) and common and preferred share dividends ($110 million)
Non-controlling interests	123	Sale of economic interests to TransAlta Renewables, partially offset by distributions paid and payable to non-controlling interests
Other	(6)	
Total decrease in liabilities and equity	**49**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2016, compared to the years ended Dec. 31, 2015 and Dec. 31, 2014:

Year ended Dec. 31	**2016**	2015	**Primary factors explaining change**
Cash and cash equivalents, beginning of year	**54**	43	
Provided by (used in):			
Operating activities	**744**	432	Favourable change in non-cash working capital of $315 million
Investing activities	**(327)**	(573)	Lower additions to property, plant, and equipment ($118 million), a higher decrease in finance lease receivables ($33 million), and a decrease in our renewable asset acquisitions ($101 million)
Financing activities	**(163)**	149	Increase in repayments of borrowings under credit facilities ($533 million), lower issuance of long-term debt ($126 million), lower proceeds on the sale of non-controlling interest in a subsidiary ($242 million), higher distributions paid to subsidiaries' non-controlling interests ($52 million), and lower realized gains on financial instruments ($89 million), partially offset by lower dividends paid to common shareholders ($55 million) and lower repayment of long-term debt ($670 million).
Translation of foreign currency cash	**(3)**	3	
Cash and cash equivalents, end of year	**305**	54	

Year ended Dec. 31	**2015**	2014	**Primary factors explaining change**
Cash and cash equivalents, beginning of year	**43**	42	
Provided by (used in):			
Operating activities	**432**	796	Decrease in cash earnings of ($49 million) and an adverse change in non-cash working capital of ($315 million)
Investing activities	**(573)**	(292)	A decrease in proceeds on the sale of investment of ($224 million) and the acquisition of solar and wind assets for ($101 million)
Financing activities	**149**	(503)	Reduction in the net decrease in borrowings of ($500 million), an increase in proceeds on the sale of non-controlling interest in a subsidiary of ($275 million), and an increase in realized gains on financial instruments of ($52 million), partially offset by a decrease in net proceeds on the issuance of preferred shares of ($161 million)
Translation of foreign currency cash	**3**	-	
Cash and cash equivalents, end of year	**54**	43	

Unconsolidated Structured Entities or Arrangements

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

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At Dec. 31, 2016, we provided letters of credit totalling $566 million (2015 - $575 million) and cash collateral of $77 million (2015 - $74 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Commitments

Contractual commitments are as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Natural gas, transportation, and other purchase contracts	40	13	6	5	5	100	**169**
Transmission	9	11	8	8	4	3	**43**
Coal supply and mining agreements[1]	163	48	49	51	52	472	**835**
Long-term service agreements	79	29	24	41	30	51	**254**
Non-cancellable operating leases[2]	7	7	7	7	7	68	**103**
Long-term debt[3]	623	959	461	460	63	1,745	**4,311**
Principal payments on finance lease obligations	16	14	10	8	6	19	**73**
Interest on long-term debt and finance lease obligations[4]	219	174	143	117	91	764	**1,508**
Growth	181	5	1	-	-	-	**187**
TransAlta Energy Bill	6	6	6	6	6	12	**42**
Total	**1,343**	**1,266**	**715**	**703**	**264**	**3,234**	**7,525**

As part of the TransAlta Energy Bill signed into law in the State of Washington and the subsequent MoA, we have committed to fund US$55 million over the remaining life of the U.S. Coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required.

I. Line Loss Rule Proceeding

TransAlta is participating in a line loss rule proceeding (the "LLRP") which is currently before the AUC. The AUC determined that it had the ability to retroactively adjust line loss rates beginning in 2006 and has directed the Alberta Electric System Operator (the "AESO"), among other actions, to perform such calculations. The various decisions by the AUC are subject to appeal and challenge. TransAlta may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP remains uncertain and the potential exposure, if any, cannot be calculated with any degree of certainty until the retroactive calculations are made available. The AESO expects retroactive calculations to be available mid-2017, at the earliest. As a result, no provision has been recorded. Certain PPAs for TransAlta's Alberta facilities provide for the pass through of these types of transmission charges to TransAlta's buyers.

(1) Commitments related to Sheerness and Genesee 3 may be impacted by the cessation of coal-fired emissions on or before Dec. 31, 2030.
(2) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.
(3) Excludes impact of derivatives.
(4) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices, and currency fluctuations, as well as other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps, and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale, or usage requirements ("own use") and as such, are not considered financial instruments and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge. Our financial instruments are categorized as fair value hedges, cash flow hedges, net investment hedges, or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion

is recognized in net earnings.

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

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Fair Value Hedges

Fair value hedges are used to offset the impact of changes in the fair value of fixed rate long-term debt caused by variations in market interest rates. We use interest rate swaps in our fair value hedges.

In a fair value hedge, changes in the fair value of the hedging instrument (an interest rate swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings. The carrying amount of long-term debt subject to the hedge is adjusted for losses or gains associated with the hedged risk, with the corresponding amounts recognized in net earnings. As a result, only the net ineffectiveness is recognized in net earnings.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate, or commodity hedges and are used to offset foreign exchange, interest rate, and commodity price exposures resulting from market fluctuations.

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures.

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps are used to offset the exposures resulting from foreign-denominated long-term debt. Interest rate swaps are used to convert the fixed interest cash flows related to interest expense at debt to floating rates and vice versa.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in OCI. These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

When we do not elect hedge accounting, or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest, or exchange rates related to these financial instruments are recorded in net earnings in the period in which they arise.

Net Investment Hedges

Foreign currency forward contracts and foreign-denominated long-term debt have historically been used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. In late 2016 we modified our net investment hedging practices and are no longer using foreign currency forward contracts in our hedges. Our net investment hedges using U.S.-denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our US dollar debt.

Non-Hedges

Financial instruments not designated as hedges are used for proprietary trading and to reduce commodity price, foreign exchange, and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings in the period in which the change occurs.

Fair Values

The majority of fair values for our project, foreign exchange, interest rate, commodity hedges, and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2016, Level III instruments had a net asset carrying value of $758 million. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2015, with the exception of the changes to our net investment hedge strategy, as discussed above and in the Governance and Risk Management section of this MD&A.

2017 Financial Outlook

For 2017, we expect our results to be slightly better than 2016 given the positive contribution from South Hedland, which is expected to be operational by mid-2017, and the receipt of the first coal transition payment from the Government of Alberta. The outlook also accounts for expected continuing weak power prices in Alberta, the Pacific Northwest, and the impact of lower priced power hedges in 2017. Approximately 85 per cent of our capacity in Alberta is

contracted, either through power PPAs or financial contracts at an average price of $45 MWh to $50 MWh. Our performance next year will also be impacted by an increase in our fuel costs caused by a planned major outage to one of the large draglines at the Highvale Mine.

The following table outlines our expectation on key financial targets for 2017:

Measure	Target
Comparable EBITDA	$1,025 million to $1,135 million
Comparable FFO	$765 million to $855 million
Comparable FCF	$300 million to $365 million
Dividend	$0.16 per share annualized, 13 to 15 per cent payout of Comparable FCF

Operations

Availability

Availability of our coal fleet is expected to be in the range of 86 to 88 per cent in 2017. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent.

Fuel Costs

The cost to mine coal in Alberta is expected to increase due to a major outage of a dragline. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2017, on a standard cost per tonne basis, are expected to be approximately 12 per cent higher than 2016 unit costs.

In the Pacific Northwest, our U.S. Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost will increase slightly in 2017 primarily due to higher transportation costs.

Most of our generation from gas is sold under contract with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

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

Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2017 objective for Energy Marketing is for the segment to contribute between $70 million to $90 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar, and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2017 is expected to be higher than in 2016 largely due to lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the US dollar can affect the amount of net interest expense incurred.

Net Debt, Liquidity, and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.7 billion in liquidity including more than $300 million in cash. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in 2017 and 2018.

Capital Expenditures

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

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

	Total Project		2017	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
South Hedland power project[2]	576	336	230 - 250	Q2 2017	150 MW combined-cycle power plant
Solomon load bank facility	5	2	3	Q1 2017	Installation of 20MW load bank facility required to support the operation of the Solomon power station
Transmission		Not applicable[3]	3	Ongoing	Regulated transmission that receives a return on investment
Total	**581**	**338**	**256 - 276**		

Cash required to fund the construction of the South Hedland power project is expected to be partially funded by proceeds from project financing and cash

generated by our business.

(1) Represents amounts spent as of Dec. 31, 2016.

(2) Estimated project expenditures are AUD$553 million. Total estimated project expenditures are stated in CAD$ and includes estimated capital interest costs. The total estimated project expenditures may change due to fluctuations in foreign exchange rates.

(3) Transmission projects are aggregated and develop on an ongoing basis. Consequently, discrete project expenditures are not available.

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

Our estimate for total sustaining and productivity capital is allocated among the following:

Category	Description	Spent in 2015	Spent in 2016	Expected spend in 2017
Routine capital[1]	Capital required to maintain our existing generating capacity	101	83	85 - 90
Planned major maintenance	Regularly scheduled major maintenance	162	148	125 - 130
Mine capital	Capital related to mining equipment and land purchases	25	23	30 - 35
Finance leases	Payments on finance leases	13	16	20 - 25
Total sustaining capital excluding flood-recovery capital		**301**	**270**	**260 - 280**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	4	2	-
Total sustaining capital		**305**	**272**	**260 - 280**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	6	8	10 - 15
Total sustaining and productivity capital		**311**	**280**	**270 - 295**

Significant planned major outages for 2017 include the following:

§ four major outages in which two relate to our partners, and a major outage to draglines at our Canadian Coal segment,

§ three major outages in our Canadian Gas segment related to our Sarnia and Windsor facilities,

§ one major outage in our Alberta Hydro segment and distributed planned maintenance expenditures across the entire fleet, and

§ distributed expenditures across our wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for U.S. Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2017:

	Coal	Gas and Renewables	Total
GWh lost	895 - 905	200 - 230	1,095 - 1,135

Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, existing liquidity, and capital raised from our contracted cash flows. We have access to approximately $1.7 billion in liquidity, if required. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

(1) Includes hydro life extension expenditures.

Sustainable Development Targets

Our 2017 and longer-term sustainability targets support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas. We continue to evolve and adapt targets to focus on anticipated key areas of materiality to stakeholders. Targets are outlined below:

	Human and Intellectual	**Annual Performance Status**
1. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.50	33 per cent improvement over 2016 target of 0.75
2. Manage employee turnover	Maintain voluntary turnover percentage under eight per cent	Consistent with 2016 target, we seek to maintain voluntary turnover under 8 per cent as this is considered a healthy amount of turnover
3. Support employee development	Continue development plans for all high-potential employees at the top three levels of the organization	Consistent with 2016 target, ongoing leadership development process

	Natural	**Annual Performance Status**
4. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 11	15 per cent improvement over 2016 target (13)
5. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 74 acres/year	Consistent with 2016 target (74 acres)
6. Utilize coal by-product	Sell a minimum of two million tonnes of coal byproduct materials during the period 2015 to 2017	70 per cent achieved (on a target to meet 2 million tonnes in 2017)
7. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030	Consistent with 2016 (long-term target)
8. Reduce GHG emissions	Our goal, in line with a commitment to the UN Sustainable Development Goals (SDGs), is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels	Revised baseline to align with COP21 commitments and target aligned with UN Sustainable Development Goals
	Our goal, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming, is to reduce our total greenhouse gas emissions in 2030 to 60 per cent below 2015 levels	Revised baseline to align with COP21 commitments; target aligned with Science Based Targets Initiative and prevention of two degrees Celsius of global warming; and target aligned with UN SDGs

	Social and Relationship	**Annual Performance Status**
9. Support youth education with community investment	Approximately $0.75 million of community investment spending will be directed to supporting youth education	Revision from 2015, which was 50% of total community investment spending directed to youth education
10. Increase internal best practice Aboriginal engagement awareness	Develop an engagement and consultation best practices document for project planning and development as a guide for employees to work with indigenous communities and stakeholders	New target

	Comprehensive	**Annual Performance Status**
10. Transition from coal to gas-fired and renewable generation	Continue negotiations with the Government of Alberta, using a principles-based approach, to ensure we have regulation certainty and the capacity needed to invest in clean power	New target

Governance and Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics, and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multilevel risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface.

Governance

The key elements of our governance practices are:

§ employees, management and the Board are committed to ethical business conduct, integrity, and honesty,

§ we have established key policies and standards to provide a framework for how we conduct our business,

§ the Chair of our Board and all directors, other than our Chief Executive Officer (“CEO”) are independent,

§ the Board is comprised of individuals with a mix of skills, knowledge, and experience that are critical for our business and our strategy,

§ the effectiveness of the Board is achieved through annual evaluations and continuing education of our directors, and

§ our management and Board facilitate and foster an open dialogue with shareholders and community stakeholders.

Commitment to ethical conduct is the foundation of our corporate governance model. We have adopted the following codes of conduct to guide our business decisions and everyday business activities:

§ Corporate Code of Conduct, which applies to all employees and officers of TransAlta and its subsidiaries,

§ Directors' Code of Conduct,

§ Finance Code of Ethics, which applies to all financial employees of the Corporation, and

§ Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our codes of conduct outline the standards and expectations we have for our employees, officers, and directors with respect to the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, conflicts of interest, respect in the workplace, social responsibility, privacy, compliance with laws, insider trading, environment, health and safety, and our commitment to ethical and honest conduct. Our Corporate Code of Conduct goes beyond the laws, rules, and regulations that govern our business in the jurisdictions in which we operate; it outlines the principal business practices with which all employees must comply.

Our employees, officers, and directors are reminded annually about the importance of ethics and professionalism in their daily work, and must certify annually that they have reviewed and understand their responsibilities as set forth in the respective codes of conduct. This certification also requires our employees, officers, and directors to acknowledge that they have complied with the standards set out in the respective code during the last calendar year.

The Board provides stewardship of the Corporation and ensures that the Corporation establishes key policies and procedures for the identification, assessment, and management of principal risks and strategic plans. The Board monitors and assesses the performance and progress of the Corporation's goals through candid and timely reports from the CEO and the senior management team. We have also established an annual evaluation process whereby our directors are provided with an opportunity to evaluate the Board, Board committees, individual directors, and the chair's performance.

In order to allow the Board to establish and manage the financial, environmental, and social elements of our governance practices, the Board has established the Audit and Risk Committee ("ARC"), the GEC, and the Human Resources Committee (the "HRC").

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

The GEC is responsible for developing and recommending to the Board a set of corporate governance principles applicable to the Corporation and for monitoring the compliance with these principles. The GEC is also responsible for Board recruitment and for the nomination of directors to the Board and its committees. In addition, the GEC assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations and public policy changes and the establishment and adherence to environmental, health and safety practices, procedures, and policies. The GEC also receives an annual report on the annual Corporate Code of Conduct certification process.

In regards to overseeing and seeking to ensure that the Corporation consistently achieves strong environment, health, and safety ("EH&S") performance, the GEC undertakes a number of actions that include: (i) receiving regular reports from management regarding environmental compliance, trends, and TransAlta's responses; (ii) receiving reports and briefings on management's initiatives with respect to changes in climate change legislation, policy developments as well as other draft initiatives and the potential impact such initiatives may have on our operations; (iii) assessing the impact of the GHG policies implementation and other legislative initiatives on the Corporation's business; (iv) reviewing with management the EH&S policies of the Corporation; (v) reviewing with management the health and safety practices implemented within the Corporation, as well as the evaluation and training processes put in place to address problem areas; (vi) receiving reports from management on the near-miss reporting program and discussing with management ways to improve the EH&S processes and practices; and (vi) reviewing the effectiveness of our response to EH&S issues and any new initiatives put in place to further improve the Corporation's EH&S culture.

The HRC is empowered by the Board to review and approve key compensation and human resources policies of the Corporation that are intended to attract, recruit, retain, and motivate employees of the Corporation. The HRC also makes recommendations to the Board regarding the compensation of the Corporation's executive officers, including the review and adoption of equity-based incentive compensation plans, the adoption of human resources policies that support human rights and ethical conduct, and the review and approval of executive management succession and development plans.

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

The CEO and senior management review key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity and Compliance Risk Committee, and weekly by the Managing Director Commodity Risk, the commercial managing directors in Trading and Marketing, and the Senior Vice-President Trading and Marketing.

The Investment Committee is chaired by our Chief Financial Officer and is comprised of the CEO, Chief Financial Officer, Chief Legal and Compliance Officer and Corporate Secretary, and Chief Investment Officer. It reviews and approves all major capital expenditures including growth, productivity, life extensions, and major coal outages. Projects that are approved by the committee will then be put forward for approval by the Board, if required.

The Commodity Risk & Compliance Committee is chaired by our Chief Financial Officer and is comprised of the Chief Financial Officer, Chief Legal and Compliance Officer and Senior Vice President, Energy Marketing. It oversees the risk and compliance program in trading and ensures that this program is adequately resourced to monitor trading operations from a risk and compliance perspective. It also ensures the existence of appropriate controls, processes, systems and procedures to monitor adherence to policy.

TransAlta is listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange and is subject to the governance regulations, rules, and standards applicable under both exchanges. Our corporate governance practices meet the following governance rules of the TSX and Canadian Securities Administrators: (i) Multilateral Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings; (ii) Multilateral Instrument 52-110 - Audit Committees; (iii) National Policy 58-201 - Corporate Governance Guidelines; and (iv) National Instrument 58-101 - Disclosure of Corporate Governance

Practices. As a “foreign private issuer” under U.S. securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our management proxy circular.

Risk Controls

Our risk controls have several key components:

Enterprise Tone
We strive to foster beliefs and actions that are true to, and respectful of, our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies
We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a code of conduct on an annual basis.

Reporting
On a regular basis, residual risk exposures are reported to key decision makers including the Board, senior management, and the Commodity Risk & Compliance Committee. Reporting to this committee includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion and review of the status of actions to minimize risks. This quarterly reporting provides for effective and timely risk management and oversight.

Whistleblower System
We have a process in place where employees, shareholders, or other stakeholders may anonymously report any potential ethical concerns. These concerns can be submitted confidentially and anonymously, either directly to the ARC or to TransAlta’s Ethics Helpline. All complaints are investigated and the ARC receives a report at every scheduled committee meeting on all findings. If the findings are urgent, they will be reported to the Chair of the Board immediately.

Value at Risk and Trading Positions
Value at risk (“VaR”) is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2016, associated with our proprietary commodity risk management activities was $2 million (2015 - $5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

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

For some risk factors we show the after-tax effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes in 2016. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk
Volume risk relates to the variances from our expected production. For example, the financial performance of our Hydro, Wind, and Solar operations is partially dependent upon the availability of their input resources in a given year. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- actively managing our assets and their condition in order to be proactive in plant maintenance so that our plants are available to produce when required;
- monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities;
- placing our facilities in locations that we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require; and
- diversifying our fuels and geography as one way of mitigating regional or fuel-specific events.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	10

Generation Equipment and Technology Risk
There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal, and corrosion damage in boilers, generators, and turbines, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we may be required to compensate the purchaser for the loss in the availability of production or record reduced energy or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

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

We manage our generation equipment and technology risk by:

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

Commodity Price Risk

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

We manage the financial exposure associated with fluctuations in electricity price risk by:

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

In 2016, we had approximately 88 per cent (2015 - 90 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfil our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the costs of fuels used in production by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants,
- hedging emissions costs by entering into various emission trading arrangements, and
- selectively using hedges, where available, to set prices for fuel.

In 2016, 79 per cent (2015 - 66 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2015 - 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings, assuming production consistent with 2016 and applying the contractual profile in place at Dec. 31, 2016, are shown below:

Factor	Increase or decrease	Approximate impact on net earnings and cash flow
Electricity price - Canada	$ 1.00/MWh	2
Electricity price - U.S.	US$ 1.00/MWh	2
Natural gas price	$0.10/GJ	1

Actual variations in net earnings can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability, and other factors.

Coal Supply Risk

Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities. At our coal-fired plants, input costs, such as diesel, tires, the price and availability of mining equipment, the volume of overburden removed to access coal reserves, rail rates, and the location of mining operations relative to the power plants are some of the exposures in our operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At U.S. Coal, interruptions at our supplier's mine, the availability of trains to deliver coal, and the financial viability of our coal suppliers could affect our ability to generate electricity.

We manage coal supply risk by:

- ensuring that the majority of the coal used in electrical generation in Alberta is from reserves permitted through coal rights we have purchased or for which we have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at U.S. Coal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- contracting sufficient trains to deliver the coal requirements at U.S. Coal,
- ensuring coal inventories on hand at Canadian Coal and U.S. Coal are at appropriate levels for usage requirements,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,

§ monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants,

§ monitoring the financial viability of U.S. coal suppliers, and

§ hedging diesel exposure in mining and transportation costs.

Environmental Compliance Risk

Environmental compliance risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada (including as set forth in the Alberta Climate Leadership Plan) and the U.S. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by reducing the operating life of generating facilities, imposing additional costs on the generation of electricity, such as emission caps or tax, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental compliance risk by:

§ seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,

§ having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety management system in place that is designed to continuously improve performance,

§ committing significant experienced resources to work with regulators in Canada and the U.S. to advocate that regulatory changes are well designed and cost effective,

§ developing compliance plans that address how to meet or surpass emission standards for GHGs, mercury, SO_2, and NOx, which will be adjusted as regulations are finalized,

§ purchasing emission reduction offsets,

§ investing in renewable energy projects, such as wind, solar, and hydro generation, and

§ incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

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

Credit Risk

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

We manage our exposure to credit risk by:

§ establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits, and the credit concentration with any specific counterparty,

§ requiring formal sign-off on contracts that include commercial, financial, legal, and operational reviews,

§ requiring security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfil its obligation or goes over its limits, and

§ reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

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

Our credit risk management profile and practices have not changed materially from Dec. 31, 2015. We had no material counterparty losses in 2016. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2016:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	92	8	**100**	**703**
Long-term finance lease receivables[2]	36	64	**100**	**719**
Risk management assets[1]	100	-	**100**	**1,034**
Total				**2,456**

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $14 million (2015 - $44 million).

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) We have one non-investment grade customer whose outstanding balance accounted for $445 million (Dec. 31, 2015 - $446 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

Currency Rate Risk

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

We manage our currency rate risk by establishing and adhering to policies that allow for both designated hedges and economic hedges and include:

§ hedging our net investments in U.S. operations using U.S.-denominated debt,

§ entering into forward foreign exchange contracts to hedge future foreign denominated expenditures including our U.S.-denominated debt that is outside the net investment portfolio, and

§ hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year, and 30 per cent in the fourth year. The U.S. exposure will be managed with a combination of interest expense on our U.S.-denominated debt and forward foreign exchange contracts; the Australian exposure will be managed with forward foreign exchange contracts.

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

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.04	12

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to engage in trading and hedging activities, capital projects, debt refinancing and payment of liabilities, capital structure, and general corporate purposes. Investment grade credit ratings support these activities and provide a more reliable and cost-effective means to access capital markets through commodity and credit cycles. Changes in credit ratings may also affect our ability and/or the cost of establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment. Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may challenge our ability to enter into these contracts or any ordinary course contract, decrease the credit limits granted, and increase the amount of collateral that may have to be provided. Certain existing contracts contain credit rating contingent clauses, that, when triggered, automatically increase costs under the contract or require additional collateral to be posted. Where the contingency is based on the lowest single rating, a one-level downgrade from a credit rating agency with an originally higher rating may not, however, trigger additional direct adverse impact.

We are focused on strengthening our financial position and flexibility and achieving stable investment grade credit ratings with rating agencies. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlooks, are set out in the Financial Capital section of this MD&A. Credit ratings are subject to revision or withdrawal at any time by the rating organization, and there can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, resulting in the adverse possible impacts identified above.

As at Dec. 31, 2016, we have liquidity of $1.7 billion comprised of amounts not drawn under our committed credit facilities and cash on hand, and foresee no current need to draw down on this liquidity in 2017.

We manage liquidity risk by:

§ monitoring liquidity on trading positions,

§ preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,

§ reporting liquidity risk exposure for commodity risk management activities on a regular basis to the Commodity Risk & Compliance Committee, senior management, and the ARC,

§ maintaining investment grade credit ratings; and

§ maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

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

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

§ employing a combination of fixed and floating rate debt instruments, and

§ monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2016, approximately six per cent (2015 - nine per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	0.15	-

Project Management Risk

On capital projects, we face risks associated with cost overruns, delays, and performance.

We manage project risks by:

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

Human Resource Risk

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

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

We manage this risk by:

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

In 2016, 53 per cent (2015 - 54 per cent) of our labour force was covered by 11 (2015 - 11) collective bargaining agreements. In 2016, five (2015 - two) agreements were renegotiated. We anticipate the successful negotiation of five collective agreements in 2017.

Regulatory and Political Risk

Regulatory and political risk is the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market regulation and re-regulation, increased oversight and control, structural or design changes in markets, or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business. This risk includes, among other things, uncertainties associated with the development of capacity markets for electricity in the provinces of Alberta and Ontario, uncertainties associated with the development of carbon pricing policies, the qualification of our renewable facilities in Alberta to the generation of tradable GHG allowances as part of the transition from the Specified Gas Emitters Regulation to new regulation to be formulated to give effect to the Alberta Climate Leadership Plan in 2018, as well as the influence of regulation on the value of allowances or credits generated.

We manage these risks systematically through our Legal and Regulatory groups and our Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electricity system operators, and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design, and we engage in market-sponsored stakeholder engagement processes. Through these and other avenues, we engage in advocacy and policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer term.

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

Transmission Risk

Access to transmission lines and transmission capacity for existing and new generation are key in our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in markets in which we operate continue to increase because new connections to the power system are consuming transmission capacity quicker than it is being added by new transmission developments.

Reputation Risk

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

We manage reputation risk by:

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

Corporate Structure Risk

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

Cyber Security Risk

We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. Cyber-attacks or other breaches of network or information technology systems security may cause disruptions to our operations. Cyber attackers may use a range of techniques, from manipulating people to using sophisticated malicious software and hardware on a single or distributed basis. Some cyber attackers use a combination of techniques in their attempt to evade safeguards such as firewalls, intrusion prevention systems, and antivirus software found in our systems and networks. A successful attack on our systems, networks, and infrastructure may allow for the unauthorized interception, destruction, use, or dissemination of our information and may cause disruptions to our operations.

We take measures to secure our infrastructure against potential cyber-attacks that may damage our infrastructure, systems and data. Our cyber security program aligns with industry best practices to ensure that a holistic approach to security is maintained. We have implemented security controls to help secure our data and business operations, including access control measures, intrusion detection and prevention systems, logging and monitoring of network activities, and implementing policies and procedures to ensure the secure operations of the business.

While we have systems, policies, hardware, practices, data backups, and procedures designed to prevent or limit the effect of the security breaches of our generation facility and infrastructure, there can be no assurance that these measures will be sufficient and that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

General Economic Conditions

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

Income Taxes

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

The Corporation is subject to changing laws, treaties, and regulations in and between countries. Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties, or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on the Corporation.

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

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	3

Legal Contingencies

We are occasionally named as a party in various claims and legal regulatory proceedings that arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim or proceedings will be resolved in our favour or that such claims may not have a material adverse effect on us.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during renewal of the insurance policies on December 31. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

Critical Accounting Policies and Estimates

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

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

Our significant accounting policies are described in Note 2 to our audited consolidated financial statements within this Annual Report. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, and other provisions. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

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

These critical accounting estimates are described as follows:

Revenue Recognition

The majority of our revenues are derived from the sale of physical power, leasing of power facilities, and from commodity risk management activities.

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

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above.

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, and futures contracts and options, to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting when hedge accounting is not applied. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of instruments that remain open at the end of a reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities.

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

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy 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.

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access. In determining Level I fair values, we use quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

Level II
Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

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

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

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

We 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. We also have 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.

We have a Commodity Exposure Management Policy, which governs both the commodity transactions undertaken in our proprietary trading business and those undertaken to manage commodity price exposures in our generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III commodity risk management fair values are determined at Dec. 31, 2016, is an estimated total upside of $93 million (2015 - $156 million upside) and total downside of $89 million (2015 - $211 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $75 million upside (2015 - $125 million upside) and $69 million downside (2015 - $186 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$24 to US$40 for the period from 2019 to 2025, while the remaining amounts account for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that a PP&E or intangible asset is impaired. Impairment exists when the carrying amount of the asset or CGU to which it belongs exceeds its recoverable amount, which is the higher of fair value less costs of disposal and value in use.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used or in our overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the PP&E or CGU to which it belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the facilities. Appropriate discount rates reflecting the risks specific to the asset under review are used in the assessments. 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.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the

smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs, or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. We evaluate the market design, transmission constraints, and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. We evaluate synergies with regard to opportunities from combined talent and technology, functional organization, and future growth potential, and we consider our own performance measurement processes in making this determination.

As a result of our review in 2016 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Refer to the Asset Impairment Charges and Reversals section of this MD&A for further details.

Impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Project Development Costs

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

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2016, total depreciation and amortization expense was $664 million (2015 - $605 million), of which $63 million (2014 - $59 million) relates to mining equipment and is included in fuel and purchased power.

As a result of the Alberta OCA, we will cease coal-fired emissions by the end of 2030. The useful lives of the PP&E and amortizable intangibles associated with the coal assets were reduced to 2030. We also entered a Non-Utility Generator Enhanced Dispatch Contract for the Mississauga plant in December 2016. As a result, the useful life of the plant was shortened to the end of 2016.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

For purposes of the 2016 and 2015 annual goodwill impairment review, the Corporation determined the recoverable amounts of the test units by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs or groups of CGUs to which goodwill relates, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

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

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 TransAlta, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant to how we classify 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 value of certain items of revenue and expense is dependent upon such classifications.

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Deferred income tax assets of $53 million (2015 - $71 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2016. These assets primarily relate to net operating loss carryforwards. We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $712 million (2015 - $647 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2016. These liabilities are comprised primarily of taxes on unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Employee Future Benefits

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

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

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

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

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for PP&E in the period in which they are incurred if there is a legal or constructive obligation to reclaim the plant or site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2016, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $293 million (2015 - $233 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.1 billion, which will be incurred between 2017 and 2073. The majority of these costs will be incurred between 2020 and 2050. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	2
Undiscounted decommissioning and restoration provision	10	1

Other Provisions

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

Accounting Changes

A. Current Accounting Changes

I. Operating and Reportable Segments

During the first quarter, we disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Change in Estimates – Useful Lives

As a result of the Alberta OCA described above, we will cease coal-fired emissions by the end of 2030. The useful lives of the PP&E and amortizable intangibles associated with the Alberta coal assets were reduced to 2030 at the end of 2016. The useful lives may be revised or extended in compliance with our accounting policies, dependent upon future operating decisions and events.

We entered into a Non-Utility Generator Contract for the Mississauga plant in December 2016. As a result, the useful life of the plant was shortened to the end of 2016.

B. Future Accounting Changes

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

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licences of intellectual property, and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by us on Jan. 1, 2018.

We have created an implementation plan and are currently in the process of reviewing our various revenue streams and underlying contracts with customers to determine the impact, that the adoption of IFRS 15 will have on our financial statements. Our implementation plan includes an assessment of the impacts on processes and controls which may be significant. Based on our initial scoping assessment, we have identified sources of revenue that are accounted for as leases or financial instruments that are excluded from the scope of IFRS 15. Thus, we are currently focusing efforts on evaluating the effect of IFRS 15 on revenue contracts such as our long-term electricity and thermal contracts, contracts for the sale of renewable attributes, merchant power revenue, and contracts for the sale of generation byproducts. Once we have developed the necessary accounting policies, estimates, judgments, and processes with respect to our revenue streams, the incremental compilation of historical data to make reasonable quantitative estimates of the effects of the new standard will commence. We have made progress on the implementation plan for IFRS 15 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 15 on our financial statements and disclosures.

Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid to late 2017.

II. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e., recognition of credit losses), and a new hedge accounting model. IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. IFRS 9 will be applied by us on Jan. 1, 2018.

Under the classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset. The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

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

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

We have created an implementation plan and are currently in the process of reviewing our various types of financial instruments to determine the potential impact. Our implementation plan includes an assessment of the impacts on processes and controls that may be significant. Based on our initial assessments, we anticipate financial statement impacts resulting from the implementation of the expected loss impairment model. The assessment of the financial statement impacts of implementing the classification and measure of financial assets and liabilities and hedge accounting model under IFRS 9 are ongoing. We made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on our financial statements and disclosures.

Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 9 extends into mid to late 2017.

III. IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while

operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019, with early application permitted if IFRS 15 is also applied at the same time. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by us on Jan. 1, 2019.

We are in the process of completing our initial scoping assessment and expect to have an implementation plan in place by mid-2017. We anticipate most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	**2016**	2015
Revenues	**717**	595
Comparable EBITDA[1]	**374**	268
Net earnings (loss) attributable to common shareholders	**61**	(7)
Comparable net earnings attributable to common shareholders[1]	**51**	3
Comparable FFO[1]	**228**	243
Cash flow from operating activities	**122**	118
Comparable FCF[1]	**93**	174
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.21**	(0.02)
Comparable net earnings per share[1]	**0.18**	0.01
Comparable FFO per share[1]	**0.79**	0.86
Comparable FCF per share[1]	**0.32**	0.61
Dividends declared per common share	**0.08**	0.18

Financial Highlights

Comparable EBITDA for the fourth quarter of 2016 improved by $106 million compared to the same period in 2015, primarily as a result of the reversal of an $80 million provision relating to our Keephills 1 outage in 2013. Last year's comparable EBITDA was impacted by an increase to our provision of $59 million relating to prior years' Keephills 1 outage in 2013. Excluding the change to our provision, comparable EBITDA in the fourth quarter of 2016 was $33 million lower than the fourth quarter of 2015. Unrealized mark-to-market gains on our gas positions favourably affected our comparable EBITDA, but were offset by lower prices and lower availability in both our Canadian and U.S. Coal segments. Also impacting our results this quarter is lower margins from our Energy Marketing segment.

Comparable FFO decreased by $15 million to $228 million for the three months ended Dec. 31, 2016, compared to same period in 2015. The year-over-year non-cash change in our provisions totalled approximately $160 million and is excluded from comparable FFO. Comparable EBITDA also included $9 million of unrealized non-cash mark-to-market losses compared to a $6 million unrealized mark-to-market gain in 2015.

Fourth quarter comparable net earnings attributable to common shareholders was $51 million ($0.18 per share), up from the comparable net earnings of $3 million ($0.01 per share) in the same quarter last year. The Keephills 1 outage provision reversal as described above favourably impacted net earnings.

Reported net earnings attributable to common shareholders was $61 million ($0.21 per share) for the fourth quarter compared to a net loss of $7 million ($0.02 net loss per share) for the same period in 2015. The difference between comparable and reported net earnings includes the net gain on the Mississauga cogeneration facility recontracting, partially offsetting the Wintering Hills wind facility impairment charge during the quarter.

(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow and Earnings on a Comparable Basis of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

Segmented Operational Results

Comparable EBITDA and operational performance for the business is as follows:

Three months ended Dec. 31	**2016**	2015
Availability (%)[1]	**88.9**	92.9
Adjusted availability (%)[2]	**88.9**	88.4
Production (GWh)[1]	**10,624**	11,107

Comparable EBITDA		
Canadian Coal	**178**	67
U.S. Coal[3]	**14**	22
Canadian Gas[3]	**70**	57
Australian Gas[3]	**32**	34
Wind and Solar	**66**	65
Hydro	**20**	19
Energy Marketing	**13**	26
Corporate	**(19)**	(22)
Total comparable EBITDA	**374**	268

Availability and Production

Adjusted availability for the three months ended Dec. 31, 2016, was consistent with the same period in 2015. Lower production for the three months ended Dec. 31, 2016, compared to the same period in 2015 are primarily due to higher outages and derates, partially offset by paid curtailments at our Canadian Coal segment, and higher economic dispatching in Ontario as a result of lower prices at our Canadian Gas segment.

- Canadian Coal: Comparable EBITDA totalled $178 million in the fourth quarter of 2016, including the reversal of the Keephills 1 outage provision of $80 million, partially offset by unrealized losses on hedging activities. The quarter-over-quarter change in our provisions was $139 million. Excluding the adjustment to our provision, comparable EBITDA was down $28 million compared to last year mainly due to lower realized prices and lower availability due to outages and derates.
- U.S. Coal: Comparable EBITDA was down $8 million in the fourth quarter compared to the same period in 2015. The unfavourable impact of mark-to-market losses on certain forward financial contracts that do not qualify for hedge accounting was partially offset by coal inventory recoveries. In addition, lower revenue and pricing was offset by lower delivered coal costs.
- Canadian Gas: Comparable EBITDA was $70 million in the fourth quarter of 2016, an increase of $13 million, compared to the same period in 2015, primarily due to favourable unrealized mark-to-market gains on our gas positon.
- Australian Gas: Comparable EBITDA was down by $2 million during the fourth quarter of 2016, compared to the same period in 2015. The addition of capacity payments for the gas conversion project at our Solomon gas plant was offset by increased repair and maintenance expenses and unfavourable Canadian dollar foreign exchange translation.
- Wind and Solar: Comparable EBITDA was consistent in the fourth quarter with the same period in 2015.
- Hydro: Comparable EBITDA was consistent in the fourth quarter with the same period in 2015.
- Energy Marketing: Comparable EBITDA was down $13 million in the fourth quarter compared to the same period in 2015 due to lower margins and increased OM&A costs associated with share-based payment expenses.
- Corporate: Lower costs in our Corporate Segment mainly due to realized benefits of cost efficiency initiatives which were offset by reduced allocations to our business segments.

(1) Availability and production includes all generating assets under generation operations that we operate and finance leases and excludes hydro assets and equity investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.
(2) Adjusted for economic dispatching at U.S. Coal.
(3) See the Accounting Changes section of this MD&A for information on changes in the presentation of the Gas reportable segment.

Reconciliation of Non-IFRS Measures

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

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO per share and comparable FCF per share arecalculated as follows using the weighted average number of common shares outstanding during the period.

	3 months ended Dec. 31	
	2016	2015
Cash flow from operating activities	**122**	118
Change in non-cash operating working capital balances	**61**	76
Cash flow from operations before changes in working capital	**183**	194
Adjustments		
Decrease in finance lease receivable	**15**	15
Restructuring costs	**3**	11
MSA settlement payment	**25**	31
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	**-**	(10)
Other	**2**	2
Comparable FFO	**228**	243
Deduct:		

Sustaining capital	**(85)**	(52)
Insurance recoveries of sustaining capital expenditures	**-**	23
Dividends paid on preferred shares	**(10)**	(11)
Distributions paid to subsidiaries' non-controlling interests	**(40)**	(29)
Comparable FCF	**93**	174
Weighted average number of common shares outstanding in the period	**288**	284
Comparable FFO per share	**0.79**	0.86
Comparable FCF per share	**0.32**	0.61

The table below provides a reconciliation of our comparable EBITDA to our comparable FFO and comparable FCF:

	3 months ended Dec. 31	
	2016	2015
Comparable EBITDA	**374**	268
Provisions	**(79)**	76
Interest expense	**(47)**	(63)
Unrealized (gains) losses from risk management activities	**9**	(6)
Current income tax expense	**(6)**	(7)
Decommissioning and restoration costs settled	**(8)**	(4)
Realized foreign exchange gain (loss)	**(1)**	1
Non-cash gain on curtailment and amendment gain on empoyee future benefits	**-**	(8)
Capital insurance recoveries	**-**	(5)
Other non-cash items	**(14)**	(9)
Comparable FFO	**228**	243
Deduct:		
Sustaining capital	**(85)**	(52)
Insurance recoveries of sustaining capital expenditures	**-**	23
Dividends paid on preferred shares	**(10)**	(11)
Distributions paid to subsidiaries' non-controlling interests	**(40)**	(29)
Comparable FCF	**93**	174
Weighted average number of common shares outstanding in the period	**288**	284
Comparable FFO per share	**0.79**	0.86
Comparable FCF per share	**0.32**	0.61

Reconciliation of Comparable EBITDA and Comparable Net Earnings

A reconciliation of reported results to comparable results for the three months ended Dec. 31, 2016 and 2015 is as follows:

	3 months ended Dec. 31, 2016				3 months ended Dec. 31, 2015			
	Reported	**Comparable reclassifications**	**Comparable adjustments**	**Comparable total**	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	**717**	**32** [1, 2]	**2** [4]	**751**	595	32 [1, 2]	13 [4]	640
Fuel and purchased power	**280**	**(19)** [3]	**(14)** [8]	**247**	272	(16) [3]	-	256
Gross margin	**437**	**51**	**16**	**504**	323	48	13	384
Operations, maintenance, and administration	**125**	**-**	**-**	**125**	109	-	10 [5]	119
Asset impairment reversals	**28**	**-**	**(28)**	**-**	(1)	-	1 [7]	-
Restructuring provision	**-**	**-**	**-** [7]	**-**	4	-	(4) [9]	-
Taxes, other than income taxes	**7**	**-**	**-**	**7**	8	-	-	8
Net other operating (income) losses	**(193)**	**-**	**191** [8]	**(2)**	(29)	-	18 [6]	(11)
EBITDA	**470**	**51**	**(147)**	**374**	232	48	(12)	268
Depreciation and amortization	**187**	**34** [2, 3]	**(46)** [8]	**175**	136	31 [2, 3]	-	167
Operating income	**283**	**17**	**(101)**	**199**	96	17	(12)	101
Finance lease income	**17**	**(17)** [1]	**-**	**-**	17	(17) [1]	-	-
Foreign exchange gain (loss)	**(3)**	**-**	**(3)** [11]	**(6)**	3	-	8 [11]	11
Gain on sale of assets	**3**	**-**	**(4)** [10]	**(1)**	(1)	-	1 [10]	-
Earnings before interest and taxes	**300**	**-**	**(108)**	**192**	115	-	(3)	112
Net interest expense	**47**	**-**	**-**	**47**	69	-	-	69
Income tax expense (recovery)	**82**	**-**	**(40)** [12, 13]	**42**	(4)	-	(6) [13]	(10)
Net earnings (loss)	**171**	**-**	**(68)**	**103**	50	-	3	53
Non-controlling interests	**90**	**-**	**(58)** [14]	**32**	46	-	(7) [14]	39
Net earnings (loss) attributable to TransAlta shareholders	**81**	**-**	**(10)**	**71**	4	-	10	14
Preferred share dividends	**20**	**-**	**-**	**20**	11	-	-	11
Net earnings (loss) attributable to common shareholders	**61**	**-**	**(10)**	**51**	(7)	-	10	3
Weighted average number of common shares outstanding in the period	**288**			**288**	284			284

Net earnings (loss) per share attributable to common shareholders	**0.21**	**0.18**	(0.02)	0.01

Earnings on a Comparable Basis

The adjustments made to calculate comparable earnings for the three months ended Dec. 31, 2016 and 2015 are as follows. References are to the previous reconciliation table.

				3 months ended Dec. 31	
				2016	2015
Reference number	**Adjustment**	**Segment**	**Financial statement line item**		
Reclassifications:					
1	Finance lease income used as a proxy for operating revenue	Australian Gas	Revenues	**13**	13
		Canadian Gas	Revenues	**4**	4
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	Revenues	**14**	15
		Australian Gas	Revenues	**1**	-
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	Fuel and purchased power	**19**	16
Adjustments (increasing (decreasing) earnings to arrive at comparable results):					
4	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	Revenues	**2**	13
5	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	OM&A	**-**	(10)
6	Non-comparable portion of insurance recovery received	Hydro	Net other operating (income) losses	**-**	(18)
7	Asset impairment reversals	U.S. Coal	Asset impairment (reversals)	**-**	(1)
		Wind and Solar	Asset impairment (reversals)	**28**	-
8	Mississauga recontracting[1]	Canadian Gas	Net other operating (income) losses	**(131)**	-
9	Restructuring expense	Canadian Coal	Restructuring provision	**-**	2
		Corporate	Restructuring provision	**-**	2
10	Gain on Poplar Creek contract restructuring	Canadian Gas	Gain on sale of assets	**-**	1
	Non-comparable gain on sale of assets	Corporate	Gain on sale of assets	**(4)**	-
11	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	Foreign exchange loss	**(3)**	8
12	Net tax effect on comparable adjustments subject to tax	Unassigned	Income tax expense (recovery)	**9**	-
13	Reversal of a writedown of deferred income tax assets	Unassigned	Income tax expense (recovery)	**31**	6
14	Non-comparable items attributable to non-controlling interests	Unassigned	Non-controlling interests	**58**	7

(1) Reported in net other operating (income) loss of ($191 million), depreciation and amortization of ($46 million) and fuel and purchased power of ($14 million).

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due

to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at U.S. Coal. Typically, hydro facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q1 2016	Q2 2016	Q3 2016	**Q4 2016**
Revenues	568	492	620	**717**
Comparable EBITDA	279	248	244	**374**
Comparable FFO	196	175	163	**228**
Net earnings (loss) attributable to common shareholders	62	6	(12)	**61**
Comparable net earnings (loss) attributable to common shareholders	14	(20)	(11)	**51**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	0.22	0.02	(0.04)	**0.21**
Comparable net earnings (loss) per share, basic and diluted[1]	0.05	(0.07)	(0.04)	**0.18**

	Q1 2015	Q2 2015	Q3 2015	Q4 2015
Revenues	593	438	641	595
Comparable EBITDA	275	183	219	268
Comparable FFO	211	160	126	243
Net earnings (loss) attributable to common shareholders	(40)	(131)	154	(7)
Comparable net earnings (loss) attributable to common shareholders	26	(44)	(33)	3
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	(0.14)	(0.47)	0.55	(0.02)
Comparable net earnings (loss) per share, basic and diluted[1]	0.09	(0.16)	(0.12)	0.01

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

Comparable net earnings, comparable EBITDA, and comparable FFO are generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate and lower planned outages.

Net earnings attributable to common shareholders has also been impacted by the following variations and events:

- § gain on disposal of assets, following the Poplar Creek contract restructuring in the third quarter of 2015,
- § U.S. Solar and Wind acquisitions in the third quarter of 2015,
- § settlement with the Market Surveillance Administrator in the third quarter of 2015,
- § a recovery of a writedown of deferred tax assets in the fourth quarter of 2014, the third quarter of 2015, and the first and second quarters of 2016,
- § change in income tax rates in Alberta in the second quarter of 2015,
- § deferred income tax impacts of the sale of an economic interest in Australian Assets to TransAlta Renewables in the first and second quarters of 2015,
- § effects of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first, second, and third quarters of 2016,
- § effects of the Mississauga facility recontracting during the fourth quarter of 2016, and
- § effects of the Wintering Hills impairment charge during the fourth quarter of 2016.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934, as amended (“Exchange Act”) are

recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

During the first quarter of 2016, we completed the implementation of a new energy trading and risk management system. In connection with the implementation, we updated the processes that constitute our internal control over financial reporting, as necessary, to accommodate related changes to our business processes and accounting procedures.

Except as otherwise described above, there have been no other changes in our internal control over financial reporting during the year ended Dec. 31, 2016 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2016, the end of the period covered by this report, our disclosure controls and procedures were effective.

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



Dawn L. Farrell
President and Chief Executive Officer



Donald Tremblay
Chief Financial Officer

March 2, 2017

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 ("TransAlta") internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States *Securities Exchange Act of 1934).*

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

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is a suitable framework for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta'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 proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta'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 2016 consolidated financial statements of TransAlta included $626 million and $592 million of total and net assets, respectively, as of December 31, 2016, and $138 million and $13 million of revenues and net loss, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at December 31, 2016, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended December 31, 2016, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.



Dawn L. Farrell
President and Chief Executive Officer



Donald Tremblay
Chief Financial Officer

March 2, 2017

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). TransAlta Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

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

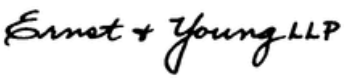
A corporation's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A corporation's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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2016 consolidated financial statements of the Corporation and constituted $626 million and $592 million of total and net assets, respectively, as of December 31, 2016, and $138 million and $13 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position as at December 31, 2016 and 2015, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the three-year period ended December 31, 2016 of TransAlta Corporation and our report dated March 2, 2017 expressed an unqualified opinion thereon.



Chartered Professional Accountants
Calgary, Canada

March 2, 2017

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated statements of financial position as at December 31, 2016 and 2015, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

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

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2016 and 2015, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2016, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 2, 2017 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 2, 2017

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2016**	2015	2014
Revenues *(Note 33)*	**2,397**	2,267	2,623
Fuel and purchased power *(Note 5)*	**963**	1,008	1,092
Gross margin	**1,434**	1,259	1,531
Operations, maintenance, and administration *(Note 5)*	**489**	492	542
Depreciation and amortization	**601**	545	538
Asset impairment charges (reversals) *(Note 6)*	**28**	(2)	(6)
Restructuring provision *(Note 4)*	**1**	22	-
Taxes, other than income taxes	**31**	29	29
Net other operating (income) losses *(Note 8)*	**(194)**	25	(14)
Operating income	**478**	148	442

Finance lease income *(Note 7)*	**66**	58	49
Net interest expense *(Note 9)*	**(229)**	(251)	(254)
Foreign exchange gain (loss)	**(5)**	4	-
Gain on sale of assets *(Note 4)*	**4**	262	2
Earnings before income taxes	**314**	221	239
Income tax expense *(Note 10)*	**38**	105	7
Net earnings	**276**	116	232
Net earnings attributable to:			
TransAlta shareholders	**169**	22	182
Non-controlling interests *(Note 11)*	**107**	94	50
	276	116	232
Net earnings attributable to TransAlta shareholders	**169**	22	182
Preferred share dividends *(Note 24)*	**52**	46	41
Net earnings (loss) attributable to common shareholders	**117**	(24)	141
Weighted average number of common shares outstanding in the year *(millions)*	**288**	280	273
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 23)*	**0.41**	(0.09)	0.52

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2016**	2015	2014
Net earnings	**276**	116	232
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**8**	4	(20)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**(1)**	3	(1)
Total items that will not be reclassified subsequently to net earnings	**7**	7	(21)
Gains (losses) on translating net assets of foreign operations, net of tax[3]	**(71)**	247	75
Reclassification of translation gains on net assets of divested foreign operations *(Note 4)*	**-**	(10)	(7)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[4]	**18**	(172)	(58)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[5] *(Note 4)*	**-**	6	7
Gains on derivatives designated as cash flow hedges, net of tax[6]	**179**	375	215
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[7]	**(48)**	(194)	(45)
Total items that will be reclassified subsequently to net earnings	**78**	252	187
Other comprehensive income	**85**	259	166
Total comprehensive income	**361**	375	398
Total comprehensive income attributable to:			
TransAlta shareholders	**215**	272	348
Non-controlling interests *(Note 11)*	**146**	103	50
	361	375	398

(1) Net of income tax expense of 4 for the year ended Dec. 31, 2016 (2015 - nil, 2014 - 7 recovery).

(2) Net of income tax expense of nil the year ended Dec. 31, 2016 (2015 - 1 expense, 2014 - nil).

(3) Net of income tax expense of 11 for the year ended Dec. 31, 2016 (2015 - nil, 2014 - nil).

(4) Net of income tax expense of 5 for the year ended Dec. 31, 2016 (2015 - 7 expense, 2014 - 7 recovery).

(5) Net of reclassification of income tax recovery of nil for the year ended Dec. 31, 2016 (2015 - 1 recovery, 2014 - 1 recovery).

(6) Net of income tax expense of 92 for the year ended Dec. 31, 2016 (2015 - 138 expense, 2014 - 91 expense).

(7) Net of reclassification of income tax expense of 41 for the year ended Dec. 31, 2016 (2015 - 50 expense, 2014 - 3 expense).

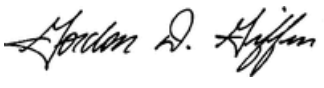
See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2016**	2015
Cash and cash equivalents	**305**	54
Trade and other receivables *(Note 12)*	**703**	567
Prepaid expenses	**23**	26
Risk management assets *(Notes 13 and 14)*	**249**	298
Inventory *(Note 15)*	**213**	219
Assets held for sale *(Note 4)*	**61**	-
	1,554	1,164
Long-term portion of finance lease receivables	**719**	775
Property, plant, and equipment *(Note 16)*		
Cost	**12,773**	12,854
Accumulated depreciation	**(5,949)**	(5,681)
	6,824	7,173
Goodwill (Note 17)	**464**	465
Intangible assets (Note 18)	**355**	369
Deferred income tax assets *(Note 10)*	**53**	71
Risk management assets *(Notes 13 and 14)*	**785**	797
Other assets *(Note 19)*	**242**	133
Total assets	**10,996**	10,947
Accounts payable and accrued liabilities	**413**	334
Current portion of decommissioning and other provisions *(Note 20)*	**39**	166
Risk management liabilities *(Notes 13 and 14)*	**66**	200
Income taxes payable	**6**	3
Dividends payable *(Note 23)*	**54**	63
Current portion of long-term debt and finance lease obligations *(Note 21)*	**639**	87
	1,217	853
Credit facilities, long-term debt, and finance lease obligations *(Note 21)*	**3,722**	4,408
Decommissioning and other provisions *(Note 20)*	**304**	232
Deferred income tax liabilities *(Note 10)*	**712**	647
Risk management liabilities *(Notes 13 and 14)*	**48**	69
Defined benefit obligation and other long-term liabilities (Note 22)	**330**	348
Equity		
Common shares *(Note 23)*	**3,094**	3,075
Preferred shares *(Note 24)*	**942**	942
Contributed surplus	**9**	9
Deficit	**(933)**	(1,018)
Accumulated other comprehensive income *(Note 25)*	**399**	353
Equity attributable to shareholders	**3,511**	3,361
Non-controlling interests *(Note 11)*	**1,152**	1,029
Total equity	**4,663**	4,390
Total liabilities and equity	**10,996**	10,947

Commitments and contingencies *(Note 32)*

Subsequent events *(Note 34)*





On behalf of the Board:

Gordon D. Giffin
Director

Alan J. Fohrer
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2014	2,999	942	9	(770)	104	3,284	594	3,878
Net earnings	-	-	-	22	-	22	94	116
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	71	71	-	71
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	177	177	7	184
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	4	4	-	4
Intercompany available-for-sale investments	-	-	-	-	(2)	(2)	2	-
Total comprehensive income				22	250	272	103	375
Common share dividends	-	-	-	(203)	-	(203)	-	(203)
Preferred share dividends	-	-	-	(46)	-	(46)	-	(46)
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	-	-	-	(21)	(1)	(22)	437	415
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(105)	(105)
Common shares issued	76	-	-	-	-	76	-	76
Balance, Dec. 31, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings	**-**	**-**	**-**	**169**	**-**	**169**	**107**	**276**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**-**	**-**	**-**	**-**	**(53)**	**(53)**	**-**	**(53)**
Net gains on derivatives designated as cash flow hedges, net of tax	**-**	**-**	**-**	**-**	**106**	**106**	**24**	**130**
Net actuarial gains on defined benefits plans, net of tax	**-**	**-**	**-**	**-**	**8**	**8**	**-**	**8**
Intercompany available-for-sale investments	**-**	**-**	**-**	**-**	**(15)**	**(15)**	**15**	**-**
Total comprehensive income				**169**	**46**	**215**	**146**	**361**
Common share dividends	**-**	**-**	**-**	**(58)**	**-**	**(58)**	**-**	**(58)**
Preferred share dividends	**-**	**-**	**-**	**(52)**	**-**	**(52)**	**-**	**(52)**
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	**-**	**-**	**-**	**26**	**-**	**26**	**138**	**164**
Distributions paid, and payable, to non-controlling interests	**-**	**-**	**-**	**-**	**-**	**-**	**(161)**	**(161)**
Common shares issued	**19**	**-**	**-**	**-**	**-**	**19**	**-**	**19**
Balance, Dec. 31, 2016	**3,094**	**942**	**9**	**(933)**	**399**	**3,511**	**1,152**	**4,663**

(1) Refer to Note 25 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)*	**2016**	2015	2014
Operating activities			
Net earnings	**276**	116	232
Depreciation and amortization *(Note 33)*	**664**	605	595
Gain on sale of assets *(Note 4)*	**(1)**	(262)	(2)
California claim *(Note 8)*	**-**	-	(28)
Accretion of provisions *(Note 20)*	**20**	21	18
Decommissioning and restoration costs settled *(Note 20)*	**(23)**	(24)	(16)
Deferred income tax expense (recovery) *(Note 10)*	**15**	86	(26)
Unrealized (gain) loss from risk management activities	**58**	61	(50)
Unrealized foreign exchange (gain) loss	**(1)**	13	11
Provisions	**(123)**	101	-
Asset impairment charges (reversals) *(Note 6)*	**28**	(2)	(6)
Other non-cash items	**(242)**	(41)	(5)
Cash flow from operations before changes in working capital	**671**	674	723
Change in non-cash operating working capital balances *(Note 29)*	**73**	(242)	73
Cash flow from operating activities	**744**	432	796
Investing activities			

Additions to property, plant, and equipment *(Notes 16 and 33)*	**(358)**	(476)	(487)
Additions to intangibles *(Notes 18 and 33)*	**(21)**	(26)	(34)
Acquisition of renewable energy facilities, net of cash acquired *(Note 4)*	**-**	(101)	-
Addition to assets held for sale	**-**	-	(13)
Proceeds on sale of property, plant, and equipment	**6**	7	6
Proceeds on sale of investments and development projects *(Note 4)*	**-**	-	224
Realized losses on financial instruments	**(6)**	(12)	(2)
Decrease in finance lease receivable	**56**	23	3
Other	**2**	24	9
Change in non-cash investing working capital balances	**(6)**	(12)	2
Cash flow used in investing activities	**(327)**	(573)	(292)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 21)*	**(315)**	218	(436)
Repayment of long-term debt *(Note 21)*	**(88)**	(758)	(551)
Issuance of long-term debt *(Note 21)*	**361**	487	434
Dividends paid on common shares *(Note 23)*	**(69)**	(124)	(140)
Dividends paid on preferred shares *(Note 24)*	**(42)**	(46)	(41)
Net proceeds on issuance of preferred shares *(Note 24)*	**-**	-	161
Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)*	**162**	404	129
Realized gains (losses) on financial instruments	**(2)**	87	35
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(151)**	(99)	(84)
Decrease in finance lease obligations *(Note 21)*	**(16)**	(13)	(10)
Other	**(3)**	(7)	-
Cash flow from (used in) financing activities	**(163)**	149	(503)
Cash flow from operating, investing, and financing activities	**254**	8	1
Effect of translation on foreign currency cash	**(3)**	3	-
Increase in cash and cash equivalents	**251**	11	1
Cash and cash equivalents, beginning of year	**54**	43	42
Cash and cash equivalents, end of year	**305**	54	43
Cash income taxes paid	**27**	17	31
Cash interest paid	**235**	242	230

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992. Its head office is located in Calgary, Alberta.

I. Generation Segments

The six generation segments of the Corporation are as follows: Canadian Coal, U.S. Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro. The Corporation owns and operates hydro, wind and solar, natural-gas- and coal-fired facilities, and related mining operations in Canada, the United States ("U.S."), and Australia. Revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Canadian Coal segment.

II. Energy Marketing Segment

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

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

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

III. Corporate

The Corporate segment includes the Corporation's central financial, legal, administrative, and investor relation functions.Charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

These consolidated financial statements have been prepared by management in compliance with International Financial Reporting Standards ("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 and assets held for sale, which are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board on March 2, 2017.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists when the Corporation is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the

subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Significant Accounting Policies

A. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be measured reliably. Revenue from the rendering of services is recognized when criteria ii), iii), and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt hour ("MWh") produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with leases are recognized as outlined in Note 2(R).

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint arrangements each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar, while the functional currencies of its subsidiary companies and joint arrangements are the Canadian, US, or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign-denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rates in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income (Loss) ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income (Loss) ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in a foreign net investment as a result of a disposal, partial disposal, or loss of control.

C. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are those non-derivative financial assets that are designated as such or that have not been classified as another type of financial asset, and are measured at fair value through OCI. Available-for-sale financial assets are measured at cost if fair value is not reliably measurable.

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

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

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

simultaneously.

Derivative instruments that are embedded in financial or non-financial contracts that are not already required to be recognized at fair value are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts and the contract is not measured at fair value. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which is recognized in OCI. Derivatives used in commodity risk management activities are described in more detail in Note 2(A).

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums, or discounts earned or incurred for financial instruments measured at amortized cost.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge, or a hedge of foreign currency exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Corporation does not apply hedge accounting, the derivative is accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. Hedge effectiveness for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivative's cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when the forecasted transaction is no longer expected to occur within the time period specified in the hedge documentation.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts and foreign-denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from changes in foreign exchange rates.

D. Cash and Cash Equivalents

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

E. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

F. Inventory

I. Fuel

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

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

II. Energy Marketing

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

III. Parts and Materials

Parts, materials, and supplies are recorded at the lower of cost, measured at moving average costs, and net realizable value.

G. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair, and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

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

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value, or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Coal generation	3-50 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction (see Note 2(S)). Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

H. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale, and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization and fuel and purchased power in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or license agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

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

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

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occurs over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

J. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

K. Project Development Costs

Project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the costs incurred subsequently are included in other assets. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

M. Employee Future Benefits

The Corporation has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the

estimated terms and currencies of the benefit obligations. Remeasurements, 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. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Corporation's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Corporation as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

N. Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Corporation determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(G)). The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. Where the Corporation expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received. Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

O. Share-Based Payments

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

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

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

Q. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position.

R. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g. a generating unit) and the arrangement conveys to the customer the right to use that asset.

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net

investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings (Loss).

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life. Rental income, including contingent rent, from operating leases is recognized over the term of the arrangement and is reflected in revenue on the Consolidated Statements of Earnings (Loss). Contingent rent may arise when payments due under the contract are not fixed in amount but vary based on a future factor such as the amount of use or production.

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

S. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

T. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used. Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

U. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. TransAlta's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues, and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Corporation reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Corporation and joint ventures is eliminated based on the Corporation's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities, and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

V. Government Incentives

Government incentives are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the incentive and that the incentive will be received. When the incentive relates to an expense item, it is recognized in net earnings over the same period in which the related costs or revenues are recognized. When the incentive relates to an asset, it is recognized as a reduction of the carrying amount of PP&E and released to earnings as a reduction in depreciation over the expected useful life of the related asset.

W. Earnings per Share

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

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

X. Business Combinations

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

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

Y. Stripping Costs

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

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

In the process of applying the Corporation's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the consolidated financial statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations, and transmission capacity or constraints for the remaining life of the facilities. Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity, and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU, or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material. The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs, or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Corporation evaluates the market design, transmission constraints, and the contractual profile of each facility, as well as the Corporation's own commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization, future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2014 to 2016 is found in Notes 6 and 17.

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 uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. See Note 10 for further details on the impacts of the Corporation's tax policies.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 13. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility, and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Joint Control

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

VI. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 20. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VIII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 3(A)(II).

IX. Employee Future Benefits

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

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets,
- the effects of changes to the provisions of the plans, and
- changes in key actuarial assumptions, including rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 27 for disclosures on employee future benefits.

X. Other Provisions

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 20 with respect to other provisions.

3. Accounting Changes

A. Current Accounting Changes

I. Operating and Reportable Segments

During the first quarter, the Corporation disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Change in Estimates - Useful Lives

As a result of the Alberta Off-Coal Arrangement described in Note 4(A), the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017,

the useful lives of the PP&E and amortizable intangibles associated with the Alberta coal assets were reduced to 2030. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

The Corporation entered into a Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") for the Mississauga plant in December 2016 as described in Note 4(D). As a result, the useful life of the plant was shortened to the end of 2016.

B. Future Accounting Changes

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

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property, and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Corporation on Jan. 1, 2018.

The Corporation has created an implementation plan and is currently in the process of reviewing its various revenue streams and underlying contracts with customers to determine the impact that the adoption of IFRS 15 will have on its financial statements. The Corporation's implementation plan includes an assessment of the impacts on processes and controls which may be significant. Based on the Corporation's initial scoping assessment, we have identified sources of revenue that are accounted for as leases or financial instruments that are excluded from the scope of IFRS 15. Thus, the Corporation is currently focusing efforts on evaluating the effect of IFRS 15 on revenue contracts such as the Corporation's long-term electricity and thermal contracts, contracts for the sale of renewable attributes, merchant power revenue, and contracts for the sale of generation byproducts. Once the Corporation has developed the necessary accounting policies, estimates, judgments and processes with respect to the Corporation's revenue streams, the incremental compilation of historical data to make reasonable quantitative estimates of the effects of the new standard will commence. The Corporation has made progress on the implementation plan for IFRS 15 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 15 on the Corporation's financial statements and disclosures.

The Corporation's current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid to late 2017. The Corporation anticipates finalizing a decision with respect to our transition method by mid-2017.

II. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e., recognition of credit losses), and a new hedge accounting model. IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. IFRS 9 will be applied by the Corporation on Jan. 1, 2018.

Under the classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset. The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

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

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

The Corporation has created an implementation plan and is currently in the process of reviewing its various types of financial instruments to determine the potential impact. The Corporation's implementation plan includes an assessment of the impacts on processes and controls that may be significant. Based on our initial assessments, the Corporation anticipates financial statement impacts resulting from the implementation of the expected loss impairment model. The assessment of the financial statement impacts of implementing the classification and measure of financial assets and liabilities and hedge accounting model under IFRS 9 are ongoing. The Corporation has made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on our financial statements and disclosures. The Corporation's current estimate of the time and effort necessary to complete our implementation plan for IFRS 9 extends into mid to late 2017.

III. IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019, with early application permitted if IFRS 15 is also applied at the same time. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by the Corporation on Jan. 1, 2019.

The Corporation is in the process of completing its initial scoping assessment and expects to have an implementation plan in place by mid-2017. We anticipate most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on the Corporation's financial statements and disclosures.

C. Comparative Figures

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

4. Significant Events

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an agreement with the Government of Alberta (the "Government") on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the Off-Coal Agreement ("OCA"), the Corporation will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to certain terms and conditions. The Off-Coal Agreement's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include: maintaining prescribed spending on investment and investment related activities in Alberta; maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels); and maintaining spending on programs and initiatives to support the communities surrounding the plants, the employees of the Corporation negatively impacted by the phase-out of coal generation, and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

The Corporation entered into a Memorandum of Understanding with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas fired conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market to be developed for the Province of Alberta.

B. Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million. The buyer and the Balancing Pool are seeking to appeal or set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. TransAlta is opposing these steps and believes they are without merit. No provision has been recognized with respect to this.

C. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP ("TAPCLP"), which holds the Corporation's interest in the Poplar Creek cogeneration facility, completed the private placement of a $202.5 million aggregate principal amount of senior secured floating rate bonds. The bonds, which mature on Dec. 31, 2030, are secured by a first ranking charge over the equity interests of the issuer that issued such bonds. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points. The interest rate for the initial period commencing on the date of issue and ending on Dec. 31, 2016 is 4.828% per annum.

D. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the NUG Contract with the Ontario's Independent Electricity System Operator (the "IESO)" for its Mississauga cogeneration facility. The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated December 2018.

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in northeastern Ontario. Further details on the NUG Contract and its impact to these financial statements can be found in Note 8.

E. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation has recorded an impairment charge of $28 million, included in the Wind and Solar segment.

F. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables Inc.'s ("TransAlta Renewables") indirect wholly-owned subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

G. Investment in and Acquisition by TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility (the "Canadian Assets")

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 megawatts ("MW") of highly contracted power generation assets located in Ontario and Québec. The transaction was originally announced on Nov. 23, 2015.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30 and December 31, and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of $13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation by issuing common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt.

Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million, through the issuance of a non-interest bearing loan payable to the Corporation.

The acquisition of the Canadian Assets was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the Canadian Assets' assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at Nov. 30, 2016, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $38 million.

H. Restructured Poplar Creek Contract and Acquisition of Wind Farms

On Sept. 1, 2015, the Corporation and Suncor Energy ("Suncor") restructured their arrangement for power generation services at Suncor's oil sands base site near Fort McMurray, Alberta.

The Corporation's Poplar Creek cogeneration facility, which has a maximum capacity of 376 MW, had been built and contracted to provide steam and electricity to Suncor until 2023 and is recorded in the gas segment. Under the terms of the new arrangement, Suncor acquired from TransAlta two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. The Corporation retained two gas turbines and heat recovery steam generators ("gas generators"), which are leased to Suncor. Suncor assumed full operational control of the cogeneration facility, including responsibility for all capital costs, and has the right to use the full 244 MW capacity of the Corporation's gas generators until Dec. 31, 2030. The Corporation provides Suncor with centralized monitoring, diagnostics, and technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030. As the new contract was determined to constitute a finance lease, the full carrying amounts of the facility were derecognized.

As part of the transaction, the Corporation acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta. The Corporation's interest in the Wintering Hills facility was accounted for as a joint operation. At Dec. 31, 2016, the Wintering Hills facility is classified as assets held for sale (see Note 4(E)).

The following table outlines the impacts of the transaction on closing in 2015, including assets and liabilities disposed of and the fair value of assets acquired and liabilities assumed:

Assets	
Finance lease receivable[(1)]	372
Property, plant, and equipment	104
Intangibles	37
Net working capital	2
Total assets acquired	**515**
Liabilities	
Decomissioning and restoration provision	3
Net assets acquired	**512**
Consideration transferred	
Property, plant, and equipment	234
Net working capital	27
Decommissioning and restoration provision	(11)
Carrying amount of transferred net assets	**250**
Gain recognized	**262**

(1) Future payments under the finance lease include $57 million annually from 2016 to 2018, and $20 million annually from 2019 to 2030. Payments have been discounted at a rate of 2.68%, based on comparative yield on borrowings of the counterparty with equivalent maturities at the time of closing.

The acquired wind farms' contribution to the Corporation's revenue and operating income since the date of acquisition until Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the wind farms would have contributed $8 million to revenues and reduced earnings before taxes by $2 million.

I. U.S. Solar and Wind Acquisition

On Oct. 1, 2015, the Corporation closed the acquisition of 100 per cent of the membership interests of Odin Wind Power LLC, owner of the 50 MW Lakeswind wind facility located in Minnesota, for cash consideration of $49 million and the assumption of certain tax equity obligations. The facility is

contracted under long-term power purchase agreements until 2034.

On Sept. 1, 2015, the Corporation closed the acquisition of 100 per cent of the membership interests of RC Solar LLC for cash consideration of $55 million. The assets acquired include 21 MW of fully contracted solar projects located in Massachusetts, which are contracted under long-term power purchase agreements ranging from 20 to 30 years, and are qualified under phase one of the Massachusetts Solar Renewable Energy Credit program.

At the 2015 acquisition dates, the fair values of the identifiable assets and liabilities of Odin Wind Power LLC and RC Solar LLC were as follows:

Assets	
Property, plant, and equipment	217
Inventory (SREC-I)	10
Net working capital	6
Total assets acquired	**233**
Liabilities	
Non-recourse debt	55
Tax equity liability	50
Deferred tax liabilities[(1)]	18
Decomissioning and restoration provision	4
Total liabilities assumed	**127**
Total consideration transferred	**106**

(1) The Corporation has recognized a corresponding deferred tax recovery in the Consolidated Statement of Earnings upon acquisition, representing deductible temporary differences now expected to be recovered.

The acquired assets' contribution to the Corporation's revenue and operating income since the date of acquisition until the end of Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the assets would have contributed $14 million to revenues and reduced earnings before taxes by $6 million.

J. Sale of Economic Interest in Australian Assets to TransAlta Renewables Inc.

On May 7, 2015, the Corporation closed the acquisition by TransAlta Renewables of an economic interest based on the cash flows of the Corporation's Australian assets. The Corporation's Australian assets consist of 575 MW of power generation from six operating assets and the South Hedland power project currently under construction, as well as the recently commissioned 270-kilometre gas pipeline. TransAlta Renewables' investment consists of the acquisition of securities that, in aggregate, provide an economic interest based on cash flows of the Australian assets broadly equal to the underlying net distributable profits. The combined value of the transaction was $1.78 billion. The Corporation continues to own, manage, and operate the Australian assets.

With the closing of the transaction, the Corporation received net cash proceeds of $211 million as well as approximately $1,067 million through a combination of common shares and Class B shares of TransAlta Renewables. The Class B shares provide voting rights equivalent to the common shares, are non-dividend paying, and will convert into common shares once the South Hedland power project is completed and commissioned.

The number of common shares that the Corporation will receive on the conversion of the Class B shares will be adjusted to reflect the actual amount funded by TransAlta Renewables for the construction and commissioning of the South Hedland power project relative to target costs of $491 million.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 common shares at a price of $12.65 per share. The offering closed in two parts on April 15 and 23, 2015. TransAlta Renewables shareholder approval was received on May 7, 2015. TransAlta Renewables received approximately $226 million in gross proceeds, and in total, incurred $11 million in share issue costs, net of $3 million of income tax recovery. Proceeds to equity were further reduced by dividend- equivalent payments of $1 million.

K. Sale of TransAlta Renewables Shares to Alberta Investment Management Corporation

On Nov. 26, 2015, the Corporation completed the sale to Alberta Investment Management Corporation ("AIMCo") of 20,512,820 common shares of TransAlta Renewables for gross proceeds of $200 million (net proceeds of $193 million). As a result, TransAlta's ownership interest was reduced from approximately 76.1 per cent to approximately 66.6 per cent (including the Class B common shares).

As part of the AIMCo investment, TransAlta Renewables granted to AIMCo a pre-emptive right to purchase such number of common shares of TransAlta Renewables in respect of any future offerings of common shares, or securities convertible into common shares, in order to allow AIMCo to maintain its proportionate shareholdings in TransAlta Renewables, provided that AIMCo's ownership remains above a specific threshold.

L. Restructuring Provision

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at its Canadian Coal power generation operations, resulting in the elimination of positions. On Sept. 29, 2015, the Corporation further reduced its overhead costs by eliminating positions primarily at its corporate head office in Calgary.

M. Changes in Internal Capitalization of U.S. Entities

On Dec. 15, 2015, the Corporation partially redeemed its net investment in a wholly owned subsidiary. As a result, the Corporation reclassified from OCI pro rata cumulative translation gains of $10 million, offset by related pro rata cumulative after-tax losses of $6 million from the net investment hedge.

N. Disposal of CE Generation, LLC

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

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

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

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2016**		2015		2014	
	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	**755**	**-**	775	-	937	-
Coal inventory writedown (recovery)	**(4)**	**-**	22	-	19	-
Purchased power	**143**	**-**	147	-	75	-
Mine depreciation	**63**	**-**	59	-	56	-
Salaries and benefits	**6**	**249**	5	250	5	280
Other operating expenses	**-**	**240**	-	242	-	262
Total	**963**	**489**	1,008	492	1,092	542

6. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets extending to the last planned asset retirement in 2073.

A. 2016

In 2016, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section III below.

During 2016, uncertainty continued to exist within the province of Alberta regarding the government's previously announced Climate Leadership Plan and the future design parameters of the electricity market. Additionally, economic conditions, while more stable than in 2015, contributed to continued over-supply conditions and depressed market prices. The Corporation assessed whether these factors presented an indicator of impairment for its Alberta Merchant CGU, and in consideration of the composition of this CGU and events arising during the latter part of 2016, which are more fully discussed below in I, determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, the Corporation did not perform an in-depth impairment analysis, but sensitivities associated with these factors were performed to confirm the continued existence of an adequate excess of estimated recoverable amount over net book value.

Through the Corporation's ongoing monitoring of potential factors, such as market, economic, and operating conditions, in other jurisdictions in which its plants operate, it concluded that no indicators of impairment were present as related to its other plants.

There was one impairment charge of $28 million related to the Wintering Hills facility (see Note 4(E) and III below) and no reversals of impairment made during the year ended Dec. 31, 2016.

I. Alberta Merchant CGU

In 2015, the Government of Alberta announced its Climate Leadership Plan ("CLP"), which broadly called for the phase-out of coal-generated electricity by 2030, and proposed the imposition of additional compliance obligations for greenhouse gas ("GHG") emissions in the province. In 2016, the Alberta government refined its approach to GHG by instituting a levy on carbon emissions in excess of defined limits, amounting to $20 per tonne in 2017 and $30 per tonne in 2018. At the federal level, the Canadian government announced its intention to implement a national price on greenhouse gas emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022.

On Nov. 24, 2016, the Corporation reached an Off-Coal Agreement with the Alberta government to receive annual cash payments of approximately $37.4 million, net to the Corporation (see Note 4(A) for further details) in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, the Corporation entered into a Memorandum of Understanding (the "MOU") on Nov. 24, 2016, with the purpose of collaborating and co-operating to advance objectives of the Alberta Climate Leadership Plan. Specifically, the parties undertook to collaborate on, among other things:

- a move toward a capacity market, commencing in 2021, compared to the current energy-only market. Under a capacity market, generators are compensated for their available capacity;
- development of a policy and to facilitate the economic conversion of some coal-fired generation to natural-gas-fired generation in Alberta, including securing regulatory co-operation from the federal government; and
- policy development to address the value of carbon reductions in the generation of electricity from existing wind and hydro production, the development of effective supporting mechanisms to ensure that existing renewable generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Alberta government and the Corporation and does not impose any obligations on, or constrain the discretion and authority of the Alberta government. The announcement of the intention to move to a capacity market is expected to impact the

Alberta market mechanisms. The Alberta government has not provided further detail on the market rules or construct. The introduction of a capacity market to replace Alberta's current market structure could impact the Corporation's determination of the Alberta Merchant CGU; however, there is not currently sufficient information from the Alberta Government to determine if a change is required. The Corporation has not modified its previous conclusions on the determination of the Alberta Merchant CGU.

During the year, the Corporation monitored the potential impacts of the CLP and other announcements on the Alberta CGU. A sensitivity analysis on these estimates to assess potential impacts of the Alberta and federal government policies on the carbon levy and GHG emissions, as well as the impacts of the Off-Coal Agreement and MOU. The analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU due to the Corporation's large merchant renewable fleet in the province.

II. Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million (see Note 4(E)). In connection with this sale, the Wintering Hills assets were accounted for as held for sale at December 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal.

III. U.S. Coal

The Corporation considered possible impairment at the U.S. Coal CGU utilizing a similar process as noted in the 2014 section below, and again found that the fair value less costs to sell approximates the current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$22.00 to US$46.00 per MWh
On-highway diesel fuel on coal shipments	US$1.69 to US$2.09 per gallon
Discount rates	5.4 to 5.7 per cent

B. 2015

In 2015, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section II below.

During 2016, uncertainty existed within the province of Alberta regarding the government's announced Climate Leadership Plan. Additionally, economic conditions contributed to continued over-supply conditions and depressed market prices. The Corporation assessed whether these factors presented an indicator of impairment for its Alberta Merchant CGU, and determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. See section I below for further assessment.

There were no impairment charges and one reversal of $2 million made during the year ended Dec. 31, 2015.

I. Alberta Merchant CGU

The slowdown in the oil and gas sector put Alberta into a recession, and placed downward pressure on demand as well as power prices. Further, on Nov. 20, 2015, the Government of Alberta announced its Climate Leadership Plan, which broadly calls for the phase-out of coal-generated electricity by 2030, and proposes the imposition of additional compliance obligations for GHG emissions in the province.

During the fourth quarter of 2015, the Corporation completed a sensitivity analysis on the estimates for the Alberta Merchant CGU to assess potential impacts of the proposed Alberta government policy on reducing GHG emissions, as well as the mandatory retirement of coal facilities by 2030. The sensitivity demonstrated an approximate fair value substantially in excess of the carrying amount of the Alberta Merchant CGU, and accordingly, no further test was performed. The excess is attributable to the Corporation's large renewable fleet in the province.

II. U.S. Coal

The Corporation considered possible impairment at the U.S. Coal CGU utilizing a similar process as noted in the 2014 section below, and again found that the fair value, less costs to sell approximates the current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$24.00 to US$50.00 per MWh
On-highway diesel fuel on coal shipments	US$2.44 to US$2.90 per gallon
Discount rates	5.2 to 6.2 per cent

III. Centralia Gas

Impairment reversals of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

B. 2014

In 2014, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section I below.

I. U.S. Coal

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

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

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

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

II. Centralia Gas

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

7. Finance Lease Receivables

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

As at Dec. 31	**2016**		2015	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**124**	**119**	121	116
Second to fifth years inclusive	**376**	**291**	414	326
More than five years	**637**	**311**	714	337
	1,137	**721**	1,249	779
Less: unearned finance lease income	**592**	**-**	648	-
Add: unguaranteed residual value	**233**	**57**	229	51
Total finance lease receivables	**778**	**778**	830	830
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease receivables *(Note 12)*	**59**		55	
Long-term portion of finance lease receivables	**719**		775	
	778		830	

8. Net Other Operating (Income) Losses

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

Year ended Dec. 31	**2016**	2015	2014
Mississauga cogeneration facility NUG Contract	**(191)**	-	-
MSA settlement	**-**	56	-
Insurance recoveries	**(3)**	(31)	(10)
California claim	**-**	-	5
Supplier settlement	**-**	-	(9)
Net other operating (income) losses	**(194)**	25	(14)

A. Mississauga Cogeneration Facility Contract

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the Ontario IESO for its Mississauga cogeneration facility. The contract is effective on Jan. 1, 2017. The Corporation has agreed to terminate the existing contract with the Ontario Electricity Financial Corporation early, which would have otherwise terminated in December 2018.

As a result of the NUG Contract, the Corporation recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling approximately $16 million. The Corporation also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. The Corporation released and recognized in earnings unrealized pre-tax net losses of $14 million from AOCI due to cash flow hedges de-designated for accounting purposes. The cash flow hedges were in respect of future gas purchases denominated in US dollars and expected to occur, between 2017 and 2018. In the fourth quarter of 2016, the forecasted gas consumption was no longer expected to occur which resulted in the cumulative loss on the hedging instrument being released from AOCI and recognized in earnings.

B. Settlement with the Market Surveillance Administrator

On March 21, 2014, the Alberta Market Surveillance Administrator (the "MSA") filed an application with the Alberta Utilities Commission (the "AUC") alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. The Corporation denied the MSA's allegations. An oral hearing took place before the AUC in December 2014. A written argument was filed in February 2015. In May 2015, further submissions were filed on a recent Supreme Court of Canada decision relevant to expert evidence. On July 27, 2015, the AUC issued a decision finding, among other things, that (i) the Corporation's actions in relation to four outage events at its coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated PPA buyers and manipulated market prices away from a competitive market outcome and (ii) the Corporation breached applicable legislation by allowing one of its employees to trade while in possession of non-public outage records. The AUC also found that the MSA did not prove, on the balance of probabilities, that the Corporation breached applicable legislation on the basis that its compliance policies, practices, and oversight thereof, were inadequate and deficient.

This AUC decision marked the end of the first phase of the proceedings. TransAlta filed for leave to appeal the AUC decision with the Alberta Court of Appeal

in August 2015. The second phase of the AUC proceedings was to consider what penalty the AUC might impose against the Corporation. On Sept. 30, 2015, TransAlta and the MSA reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which is in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the consent order, the Corporation will pay a total amount of $56 million that includes approximately $27 million as a repayment of economic benefit, $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million was paid in the fourth quarter of 2015, and the $25 million administrative penalty was paid in November of 2016. As a result of the approval, the Corporation discontinued the appeal of the AUC's decision.

C. Insurance Recoveries

During 2016, the Corporation received $3 million in insurance recoveries (2015 - $31 million, 2014 - $10 million), of which $2 million (2015 - $6 million, 2014 - $6 million) relates to business interruption insurance claims and $1 million relates to claims for replacement and refurbishment of equipment for certain wind facilities (2015 – $7 million for Canadian Coal facilities).

In 2015 and 2014 the Corporation received $18 million and $4 million of insurance recoveries, respectively, relating to claims for the replacement and refurbishment for certain hydro facilities as a result of the flooding in Southern Alberta in 2013. Additionally, in 2015 and 2014, $12 million and $18 million, respectively, of insurance proceeds were received related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in 2013 and were accounted for as a reduction to period operations, maintenance, and administration costs.

D. California Claim

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

E. Supplier Settlement

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

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2016	2015	2014
Interest on debt	**236**	228	238
Capitalized interest *(Note 16)*	**(16)**	(9)	(3)
Loss on redemption of bonds *(Note 10)*	**1**	-	-
Interest on finance lease obligations	**3**	4	1
Other	**(5)**	(2)	(1)
Keephills 1 outage interest accruals (reversals) *(Note 4)*	**(10)**	9	1
Accretion of provisions *(Note 20)*	**20**	21	18
Net interest expense	**229**	251	254

10. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2016	2015	2014
Earnings before income taxes	**314**	221	239
Net earnings attributable to non-controlling interests not subject to tax	**(109)**	(34)	(37)
Adjusted earnings before income taxes	**205**	187	202
Statutory Canadian federal and provincial income tax rate (%)	**26.7**	25.9	25.0
Expected income tax expense	**55**	48	51
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(16)**	(16)	(3)
Deferred income tax expense related to temporary difference on investment in subsidiary	**11**	95	-
MSA settlement	**-**	14	-
Reversal of writedown of deferred income tax assets	**(10)**	(56)	(5)
Statutory and other rate differences	**1**	20	-
Resolution of uncertain tax matters	**-**	-	(1)
Divestiture of investment	**-**	-	(38)
Other	**(3)**	-	3
Income tax expense	**38**	105	7
Effective tax rate (%)	**19**	56	3

II. Components of Income Tax Expense
The components of income tax expense are as follows:

Year ended Dec. 31	2016	2015	2014
Current income tax expense	**23**	24	33
Adjustments in respect of current income tax of previous years	**-**	(5)	-
Adjustments in respect of deferred income tax of previous years	**(3)**	5	2
Deferred income tax expense related to the origination and reversal of temporary differences	**16**	22	12
Deferred income tax expense related to temporary difference on investment in subsidiary[1]	**11**	95	-
Deferred income tax expense resulting from changes in tax rates or laws[2]	**1**	20	-
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	**-**	-	(35)
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets[3]	**(10)**	(56)	(5)
Income tax expense	**38**	105	7

Year ended Dec. 31	2016	2015	2014
Current income tax expense	**23**	19	33
Deferred income tax expense (recovery)	**15**	86	(26)
Income tax expense	**38**	105	7

(1) In 2016, reorganizations of certain TransAlta subsidiaries were completed in connection with the New Richmond project financing and the disposition of the Canadian Assets to TransAlta Renewables. The reorganizations resulted in the recognition of deferred tax liabilities of $3 million and $8 million, respectively. In 2015, in order to give effect to the sale of an economic interest in the Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a $95 million deferred tax liability on TransAlta's investment in a subsidiary. For both 2015 and 2016, the deferred tax liabilities had not been recognized previously, as prior to the reorganizations, the taxable temporary differences were not expected to reverse in the foreseeable future.

(2) 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016. 2015 relates to the impact of an increase in the Alberta corporate income tax rate from 10 per cent to 12 per cent, enacted June 18, 2015.

(3) During the year ended Dec. 31, 2016, the Corporation reversed a previous writedown of deferred income tax assets of $10 million (2015 - $56 million writedown reversal, 2014 - $5 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utlize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2035. Recognized other comprehensive income during the years ended Dec. 31, 2016 and 2015 have given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

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	2016	2015	2014
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**51**	89	88
Net impact related to net investment hedges	**16**	8	(6)
Net actuarial gains (losses)	**4**	-	(7)
Share issuance costs	**-**	(4)	(1)
Loss on sale of investment in subsidiary	**-**	(8)	-
Income tax expense reported in equity	**71**	85	74

C. Consolidated Statements of Financial Position
Significant components of the Corporation's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2016	2015
Net operating loss carryforwards	**768**	822
Future decommissioning and restoration costs	**103**	91
Property, plant, and equipment	**(1,114)**	(1,124)
Risk management assets and liabilities, net	**(282)**	(250)
Employee future benefits and compensation plans	**70**	70
Interest deductible in future periods	**90**	91
Foreign exchange differences on U.S.-denominated debt	**69**	74
Deferred coal revenues	**17**	16
Other deductible temporary differences	**3**	(4)
Net deferred income tax liability, before writedown of deferred income tax assets	**(276)**	(214)
Writedown of deferred income tax assets	**(383)**	(362)
Net deferred income tax liability, after writedown of deferred income tax assets	**(659)**	(576)

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

As at Dec. 31	2016	2015
Deferred income tax assets[1]	**53**	71
Deferred income tax liabilities	**(712)**	(647)
Net deferred income tax liability	**(659)**	(576)

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

D. Contingencies
As of Dec. 31, 2016, the Corporation had recognized a net liability of $7 million (2015 - $7 million) related to uncertain tax positions. There were no changes in the liability for uncertain tax positions for the year ended Dec. 31, 2016.

11. Non-Controlling Interests

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

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2016
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	40.2% - Public shareholders
Kent Hills wind farm[(1)]	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration L.P. ("TA Cogen")operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

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

A. TransAlta Renewables

The net earnings, distributions, and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 150 MW Kent Hills wind farm located in New Brunswick.

As a result of the transactions described in Note 4, the Corporation's share of ownership and equity participation in TransAlta Renewables has fluctuated since its formation as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Aug. 9, 2013 to April 28, 2014	80.7	80.7
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 and thereafter	64.0	59.8

As the Class B shares issued to the Corporation in the sale of the Australian assets were determined to constitute financial liabilities of TransAlta Renewables and do not participate in earnings until commissioning of South Hedland, they are excluded from the allocation of equity and earnings.

Year ended Dec. 31	**2016**	2015	2014
Revenues	**259**	236	233
Net earnings	**1**	198	52
Total comprehensive income	**40**	204	52
Amounts attributable to the non-controlling interests:			
Net earnings	**2**	63	15
Total comprehensive income	**18**	65	15
Distributions paid to non-controlling interests	**83**	43	28

As at Dec. 31	**2016**	2015
Current assets	**109**	74
Long-term assets	**3,732**	3,262
Current liabilities	**(537)**	(190)
Long-term liabilities	**(1,237)**	(1,120)
Total equity	**(2,067)**	(2,026)
Equity attributable to non-controlling interests	**(851)**	(787)
Non-controlling interests' share (per cent)	**40.2**	37.96

B. TA Cogen

Year ended Dec. 31	**2016**	2015	2014
Results of operations			
Revenues	**274**	288	305
Net earnings	**211**	61	71
Total comprehensive income	**258**	77	72
Amounts attributable to the non-controlling interest:			
Net earnings	**105**	31	35
Total comprehensive income	**128**	38	35
Distributions paid to Canadian Power Holdings Inc.	**68**	56	56

As at Dec. 31	**2016**	2015
Current assets	**171**	82
Long-term assets	**538**	535
Current liabilities	**(65)**	(75)
Long-term liabilities	**(35)**	(54)
Total equity	**(609)**	(488)

Equity attributable to Canadian Power Holdings Inc.	**(301)**	(242)
Non-controlling interest share (per cent)	**49.99**	49.99

12. Trade and Other Receivables

As at Dec. 31	**2016**	2015
Trade accounts receivable	**558**	433
Income taxes receivable	**9**	5
Current portion of finance lease receivables *(Note 7)*	**59**	55
Collateral paid *(Note 14)*	**77**	74
Trade and other receivables	**703**	567

13. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

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

Carrying value as at Dec. 31, 2016

	Derivatives used for hedging	**Derivatives classified as held for trading**	**Loans and receivables**	**Other financial liabilities**	**Total**
Financial assets					
Cash and cash equivalents[1]	**-**	**-**	**305**	**-**	**305**
Trade and other receivables	**-**	**-**	**703**	**-**	**703**
Long-term portion of finance lease receivables	**-**	**-**	**719**	**-**	**719**
Other assets	**-**	**-**	**116**	**-**	**116**
Risk management assets					
Current	**192**	**57**	**-**	**-**	**249**
Long-term	**749**	**36**	**-**	**-**	**785**
Financial liabilities					
Accounts payable and accrued liabilities	**-**	**-**	**-**	**413**	**413**
Dividends payable	**-**	**-**	**-**	**54**	**54**
Risk management liabilities					
Current	**1**	**65**	**-**	**-**	**66**
Long-term	**4**	**44**	**-**	**-**	**48**
Credit facilities, long-term debt and finance lease obligations[2]	**-**	**-**	**-**	**4,361**	**4,361**

[1] *Includes cash equivalents of $103 million.*

[2] *Includes current portion.*

Carrying value as at Dec. 31, 2015

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	54	-	54
Trade and other receivables	-	-	567	-	567
Long-term portion of finance lease receivables	-	-	775	-	775
Risk management assets					
Current	101	197	-	-	298
Long-term	808	(11)	-	-	797
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	334	334
Dividends payable	-	-	-	63	63
Risk management liabilities					
Current	57	143	-	-	200
Long-term	45	24	-	-	69
Credit facilities, long-term debt and finance lease obligations[1]	-	-	-	4,495	4,495

[1] *Includes current portion.*

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level I, II, and III Fair Value Measurements

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

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

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

c. Level III

Fair values are determined using inputs for the assets or liabilities 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 commodity 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, which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of observable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses.

Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at Dec. 31	**2016**	2015

Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	**907**	**+76 -69**	863	+125 -186
Long-term power sale - Alberta	**(3)**	**+5 -5**	(13)	+13 -7
Unit contingent power purchases	**13**	**+2 -4**	(70)	+9 -8
Structured products - Eastern U.S.	**24**	**+8 -8**	18	+6 -4
Hydro slice products - Western U.S.	**-**	**- -**	(6)	+1 -4
Others	**6**	**+3 -3**	(3)	+2 -2

i. Long-Term Power Sale - U.S.
The Corporation has a long-term fixed price power sale contract in the U.S. for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2018, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2016 are US$24 - US$40 (Dec. 31, 2015 - US$28 - US$45). The sensitivity analysis has been prepared using the Corporation's assessment that a US$5 price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2015 to Dec. 31, 2016, the base fair value and the sensitivity values have decreased by approximately $26 million and $2 million, respectively.

ii. Long-Term Power Sale - Alberta
The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as held for trading.

For periods beyond 2021, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high, and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2016 are $55 - $107 (Dec. 31, 2015 - $86 - $93). The sensitivity analysis has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. Unit Contingent Power Purchases
Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as held for trading.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2016 are 0.53 per cent to 0.94 per cent (Dec. 31, 2015 - 0 per cent to 2.8 per cent) and 8.41 per cent to 21.08 per cent (Dec. 31, 2015 – 1.7 per cent to 7.4 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 0.75 per cent and a change in volumetric discount rates of approximately 15.5 per cent, which approximate one standard deviation for each input.

iv. Structured Products - Eastern U.S.
The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations, or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2016, are 66 per cent to 128 per cent and 42 per cent to 95 per cent (Dec. 31, 2015 – 85 per cent to 116 per cent and 65 per cent to 109 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 5 per cent and a change in non-standard shape factors of approximately 9 per cent, which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2016 are 18 per cent to 59 per cent and 63 per cent to 77 per cent (Dec. 31, 2015 – 18 per cent to 71 per cent and 39 per cent to 80 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities and correlation of approximately 10 per cent, respectively.

v. Hydro Slice Products – Western U.S.

The Corporation agreed to purchase power contingent upon the actual generation of specific hydro units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed capacity payment. The contracts were accounted for as held for trading and expired during the fourth quarter of 2016.

The key unobservable inputs used in the Dec. 31, 2015 valuations are delivered volume expectations. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements. This analysis is based on historical production of the generation units for available history. Volumes used in the Level III base fair value measurement at Dec. 31, 2015 are within the 50th percentile of the historical production.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

The following tables summarize the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2016 and 2015, 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, 2015	-	(58)	640	-	128	(98)	-	70	542
Changes attributable to:									
Market price changes on existing contracts	**-**	**44**	**163**	**-**	**(10)**	**13**	**-**	**34**	**176**
Market price changes on new contracts	**-**	**5**	**-**	**-**	**(23)**	**29**	**-**	**(18)**	**29**
Contracts settled	**-**	**20**	**(50)**	**-**	**(121)**	**88**	**-**	**(101)**	**38**
Change in foreign exchange rates	**-**	**1**	**(27)**	**-**	**-**	**-**	**-**	**1**	**(27)**
Discontinued hedge accounting on certain contracts (see Note 4)	-	**31**	-	-	**(31)**	-	-	-	-
Net risk management assets (liabilities) at Dec. 31, 2016	**-**	**43**	**726**	**-**	**(57)**	**32**	**-**	**(14)**	**758**
Additional Level III information:									
Gains recognized in OCI			**136**			**-**			**136**
Total gains included in earnings before income taxes			**50**			**42**			**92**
Unrealized gains included in earnings before income taxes relating to net assets held at Dec. 31, 2016			**-**			**130**			**130**

	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, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	-	(18)	261	-	49	(25)	-	31	236
Market price changes on new contracts	-	1	-	-	51	(48)	-	52	(48)
Contracts settled	-	26	(28)	-	(159)	76	-	(133)	48
Change in foreign exchange rates	-	(8)	93	-	7	(4)	-	(1)	89
Net risk management assets (liabilities) at Dec. 31, 2015	-	(58)	640	-	128	(98)	-	70	542
Additional Level III information:									
Gains recognized in OCI			354			-			354
Total gains (losses) included in earnings before income taxes			28			(77)			(49)
Unrealized losses included in earnings before income taxes relating to net liabilities held at Dec. 31, 2015			-			(1)			(1)

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2016, are primarily attributable to the following factors:

§ changes in value of the long-term power sale contract (Level III hedge) as discussed in the preceding section (B)(I)(c)(i) of this note;

§ change in value of Alberta power sale contracts and eastern Canadian gas purchase contracts (Level II hedge); and

§ maturity of power contracts in the Northeast U.S. (Level II non-hedge) and maturities of unit contingent power purchases described in the section (B)(I)(c)(iii) of this note (Level III non-hedges).

III. Other Risk Management Assets and Liabilities

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

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

Other risk management assets and liabilities with a total net asset fair value of $176 million as at Dec. 31, 2016 (Dec. 31, 2015 - $214 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended Dec. 31, 2016 are primarily attributable to the weakening of the US dollar relative to the Canadian dollar on the Corporation's foreign currency hedges.

IV. Other Financial Assets and Liabilities

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

	Fair value				Total carrying value
	Level I	Level II	Level III	Total	
Long-term debt[1] - Dec. 31, 2016	**-**	**4,271**	**-**	**4,271**	**4,221**
Long-term debt[1] - Dec. 31, 2015	-	4,067	-	4,067	4,344

(1) Includes current portion and excludes $67 million (Dec. 31, 2015 - $69 million) of debt measured and carried at fair value.

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

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

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note 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, and a reconciliation of changes is as follows:

As at Dec. 31	2016	2015	2014
Unamortized net gain at beginning of year	**202**	188	160
New inception gains	**10**	28	23
Change in foreign exchange rates	**(4)**	28	14
Amortization recorded in net earnings during the year	**(60)**	(42)	(9)
Unamortized net gain at end of year	**148**	202	188

14. Risk Management Activities

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2016

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	**-**	**86**	**-**	**(16)**	**70**
Long-term	**-**	**683**	**-**	**(9)**	**674**
Net commodity risk management assets (liabilities)	**-**	**769**	**-**	**(25)**	**744**
Other					
Current	**-**	**105**	**-**	**8**	**113**
Long-term	**-**	**59**	**3**	**1**	**63**
Net other risk management assets	**-**	**164**	**3**	**9**	**176**
Total net risk management assets (liabilities)	**-**	**933**	**3**	**(16)**	**920**

As at Dec. 31, 2015

	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	31	-	57	88
Long-term	-	551	-	(27)	524
Net commodity risk management assets	-	582	-	30	612
Other					
Current	(7)	20	-	(3)	10
Long-term	-	207	5	(8)	204
Net other risk management assets (liabilities)	(7)	227	5	(11)	214
Total net risk management assets (liabilities)	(7)	809	5	19	826

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	**2016**				2015			
	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	**315**	**744**	**(113)**	**(53)**	534	1,048	(350)	(93)
Gross amounts set-off	**(24)**	**(3)**	**24**	**3**	(105)	(12)	105	12
Net amounts as presented in the Consolidated Statements of Financial Position	**291**	**741**	**(89)**	**(50)**	429	1,036	(245)	(81)

II. Hedges

a. Net Investment Hedges

The Corporation's hedges of its net investment in foreign operations are comprised of US-dollar-denominated long-term debt with a face value of US$630 million (2015 - US$580 million) and the following foreign currency forward contracts:

As at Dec. 31		**2016**		2015			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Currency Forward Contracts							
-	**-**	**-**	**-**	AUD297	CAD293	(6)	2016
-	**-**	**-**	**-**	USD76	CAD104	(1)	2016

During 2016, the Corporation de-designated its foreign currency forward contracts from its net investment hedges. The cumulative unrealized losses on these contracts will be deferred in AOCI until the disposal of the related foreign operation.

b. Cash Flow Hedges

i. Commodity Risk Management

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

As at Dec. 31	**2016**		2015	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**4,916**	**-**	7,006	-
Natural gas *(GJ)*	**-**	**-**	-	22,485

During 2016, additional unrealized pre-tax gains of $nil (2015 - $3 million, 2014 - $2 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings. The cash flow hedges were in respect of future power production expected to occur between 2012 and 2017. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using then current forward prices that changed between then and the time the contracts settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts would not change.

As at Dec. 31, 2016, cumulative gains of $4 million (2015 - $4 million) related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

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

As at Dec. 31	2016			2015			
Notional amount sold	**Notional amount purchased**	**Fair value asset**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
-	**-**	**-**	**-**	CAD138	USD126	36	2016-2018
AUD8	**JPY710**	**1**	**2017**	AUD19	JPY1,683	1	2016-2017
Foreign Exchange Forward Contracts - foreign-denominated debt							
CAD26	**USD20**	**-**	**2018**	CAD95	USD70	2	2016-2018
Cross-Currency Swaps - foreign-denominated debt							
CAD434	**USD400**	**104**	**2017**	CAD434	USD400	116	2017
CAD306	**USD270**	**59**	**2018**	CAD306	USD270	72	2018

iii. Effect of Cash Flow Hedges

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

	Year ended Dec. 31, 2016				
		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	**304**	Revenue	**(169)**	Revenue	**-**
		Fuel and purchased power	**44**	Fuel and purchased power	**31**
Foreign exchange forwards on commodity contracts	**(5)**	Revenue	**(16)**	Revenue	**(15)**
Foreign exchange forwards on project hedges	**(1)**	Property, plant, and equipment	**-**	Foreign exchange (gain) loss	**-**
Foreign exchange forwards on U.S. debt	**(2)**	Foreign exchange (gain) loss	**53**	Foreign exchange (gain) loss	**-**
Cross-currency swaps	**(25)**	Foreign exchange (gain) loss	**(23)**	Foreign exchange (gain) loss	**-**
Forward starting interest rate swaps	**-**	Interest expense	**6**	Interest expense	**-**
OCI impact	**271**	**OCI impact**	**(105)**	**Net earnings impact**	**16**

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminates the generation effective Jan. 1, 2017. Accordingly, the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 8(A) for further details.

During 2015 and 2014, total unrealized pre-tax gains of $6 million and $3 million, respectively, were released from AOCI and recognized in earnings due to hedge de-designations for accounting purposes.

	Year ended Dec. 31, 2015				
		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	308	Revenue	(110)	Revenue	5
		Fuel and purchased power	41	Fuel and purchased power	-
Foreign exchange forwards on commodity contracts	32	Revenue	(12)	Revenue	-
Foreign exchange forwards on project hedges	4	Property, plant, and equipment	(1)	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt	10	Foreign exchange (gain) loss	(12)	Foreign exchange (gain) loss	-
Cross-currency swaps	163	Foreign exchange (gain) loss	(163)	Foreign exchange (gain) loss	-
Forward starting interest rate swaps	-	Interest expense	7	Interest expense	-
OCI impact	517	OCI impact	(250)	Net earnings impact	5

Year ended Dec. 31, 2014

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		Revenue	24	Revenue	(3)
Commodity contracts	212	Fuel and purchased power	14	Fuel and purchased power	-
Foreign exchange forwards on commodity contracts	14	Revenue	(1)	Revenue	-
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	-	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt	(9)	Foreign exchange (gain) loss	6	Foreign exchange (gain) loss	-
Cross-currency swaps	89	Foreign exchange (gain) loss	(94)	Foreign exchange (gain) loss	-
Forward starting interest rate swaps	-	Interest expense	6	Interest expense	-
OCI impact	305	OCI impact	(45)	Net earnings impact	(3)

Over the next 12 months, the Corporation estimates that approximately $83 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.90 per cent (2015 - 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	**2016**		2015		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD50	**3**	**2018**	USD50	5	2018

Including interest rate swaps, 6 per cent of the Corporation's debt as at Dec. 31, 2016 is subject to floating interest rates (2015 - 9 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		**2016**	2015	2014
Derivatives in fair value hedging relationships	**Location of gain (loss) recognized in earnings**			
Interest rate contracts	Net interest expense	**(2)**	(1)	(1)
Long-term debt	Net interest expense	**2**	1	1
Earnings (loss) impact		**-**	-	-

III. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Commodity Risk Management

As at Dec. 31	**2016**		2015	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**19,362**	**19,060**	42,975	38,565
Natural gas *(GJ)*	**146,113**	**173,187**	106,203	101,100
Transmission *(MWh)*	**-**	**3,429**	-	5,014
Emissions *(tonnes)*	**1,370**	**1,370**	960	960
Heating oil *(gallons)*	**-**	**294**	-	-

b. Other Non-Hedge Derivatives

As at Dec. 31		**2016**		2015			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity

Foreign Exchange Forward Contracts							
USD152	**CAD216**	**12**	**2017-2020**	USD41	CAD54	(3)	2016-2018
AUD232	**CAD219**	**(3)**	**2017-2020**	AUD89	CAD79	(8)	2016-2020
-	**-**	**-**	**-**	AUD5	USD4	1	2016
Derivatives embedded in supplier contracts[1]							
-	**-**	**-**	**-**	USD4	AUD5	(1)	2016

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

c. Total Return Swaps

The Corporation has certain compensation, 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, 2016, the Corporation recognized a net unrealized loss of $63 million (2015 - loss of $51 million, 2014 - gain of $54 million) related to commodity derivatives.

For the year ended Dec. 31, 2016, a gain of $9 million (2015 - loss of $1 million, 2014 - gain of $10 million) related to foreign exchange and other derivatives was recognized and is comprised of net unrealized gains of $4 million (2015 - loss of $11 million, 2014 - gain of $2 million) and net realized gains of $5 million (2015 - gain of $10 million, 2014 - gain of $8 million).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

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

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

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

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2016, associated with the Corporation's proprietary trading activities was $2 million (2015 - $5 million, 2014 - $5 million).

ii. Commodity Price Risk - Generation

The generation segments utilize 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, 2016, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $19 million (2015 - $24 million, 2014 - $27 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, 2016, associated with these transactions was $7 million (2015 - $1 million, 2014 - $7 million).

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 15 basis point (2015 - 15 basis point, 2014 - 15 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2016**		2015		2014	
	Net earnings increase[1]	**OCI loss[1]**	Net earnings increase[1]	OCI loss[1]	Net earnings increase[1]	OCI loss[1]
Basis point change	**-**	**-**	**1**	-	**-**	-

(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 U.S. dollar, the Japanese yen, and the Australian dollar ("AUD"), 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.

As part of the Australian assets transaction described in Note 4(J), the Corporation entered into foreign exchange hedging contracts with TransAlta Renewables to mitigate the risks to TransAlta Renewables shareholders of adverse changes in AUD in respect of AUD$239 million remaining investments to fund the South Hedland project. In addition, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in USD and AUD in respect of cash flows from the Australian assets in relation to the Canadian dollar for the first five years from the time of the Australian Assets Transaction. The financial effects of these contracts and agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years. Hedge accounting is not applied to these foreign currency contracts and accordingly, the loss on the contracts, recognized as a foreign exchange loss, was $5 million for the year ended Dec. 31, 2016 (2015 – loss $8 million).

The Corporation also uses foreign currency contracts to hedge its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

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

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2015 and 2014 - four 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	**2016**		2015		2014	
Currency	**Net earnings increase (decrease)[1]**	**OCI gain[1], [2]**	Net earnings increase[1]	OCI gain[1], [2]	Net earnings decrease[1]	OCI gain[1], [2]
USD	**(5)**	**-**	2	5	4	5
AUD	**(7)**	**-**	(3)	-	(2)	-
Total	**(12)**	**-**	(1)	5	2	5

(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 fulfil 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.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. In certain cases, the Corporation will require security instruments such as parental guarantees, letters of credit, cash collateral or third-party credit insurance to reduce overall credit risk. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2016:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	92	8	**100**	**703**
Long-term finance lease receivables[2]	36	64	**100**	**719**
Risk management assets[1]	100	-	**100**	**1,034**
Total				**2,456**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) The Corporation has one non-investment grade customer whose outstanding balance accounted for $445 million (Dec. 31, 2015 - $446 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid-to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

The Corporation's maximum exposure to credit risk at Dec. 31, 2016, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables 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, 2016, was $14 million (2015 - $44 million).

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. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's U.S. bonds one notch from Baa3 to Ba1. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. As at Dec. 31, 2016, TransAlta maintains investment grade ratings from three credit rating agencies. TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

Counterparties enter into certain commodity agreements, such as electricity and natural gas purchase and sale contracts, for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these agreements may contain credit-contingent features (such as downgrades in creditworthiness), which if triggered may result in the Corporation having to post collateral to its counterparties.

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; and reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management, and the Board.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Accounts payable and accrued liabilities	413	-	-	-	-	-	413
Long-term debt[1]	623	959	461	460	63	1,745	4,311
Commodity risk management assets	(69)	(73)	(80)	(79)	(100)	(343)	(744)
Other risk management (assets) liabilities	(114)	(67)	3	2	-	-	(176)
Finance lease obligations	16	14	10	8	6	19	73
Interest on long-term debt and finance lease obligations[2]	219	174	143	117	91	764	1,508
Dividends payable	54	-	-	-	-	-	54
Total	**1,142**	**1,007**	**537**	**508**	**60**	**2,185**	**5,439**

(1) Excludes impact of hedge accounting.

(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, 2016, the Corporation provided $77 million (2015 - $74 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is recorded in accounts receivable in the statement of financial position.

II. Financial Assets Held as Collateral

At Dec. 31, 2016, the Corporation held $21 million (2015 - $15 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. Collateral held is contained in accounts payable in the statement of financial position.

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, 2016, the Corporation had posted collateral of $116 million (Dec. 31, 2015 - $220 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $49 million (Dec. 31, 2015 - $44 million) of collateral to its counterparties.

15. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Marketing, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	**2016**	2015
Parts and materials	**110**	116
Coal	**65**	56
Deferred stripping costs	**12**	14
Natural gas	**17**	8
Purchased emission credits	**9**	25
Total	**213**	219

The change in inventory is as follows:

Balance, Dec. 31, 2014	196
Net additions	47
Acquisition *(Note 4)*	10
Writedowns	(22)
Change in foreign exchange rates	(12)
Balance, Dec. 31, 2015	219
Net use	**(12)**
Writedowns	**(9)**
Reversal of writedowns	**13**
Change in foreign exchange rates	**2**
Balance, Dec. 31, 2016	**213**

No inventory is pledged as security for liabilities.

16. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2014	82	5,803	1,869	2,882	1,159	341	271	12,407
Additions	1	-	3	-	-	474	(2)	476
Acquisitions *(Note 4)*	-	-	-	321	-	-	-	321
Additions - finance lease	-	-	-	-	13	-	-	13
Disposals	(2)	-	(13)	-	-	-	-	(15)
Disposals - Poplar Creek *(Note 4)*	-	-	(429)	-	-	-	(7)	(436)
Impairment reversals *(Note 6)*	-	-	2	-	-	-	-	2
Revisions and additions to decommissioning and restoration costs	-	(42)	(10)	(21)	(13)	-	-	(86)
Retirement of assets	-	(106)	(19)	(18)	(11)	-	(4)	(158)
Change in foreign exchange rates	3	220	33	27	18	16	8	325
Transfers	11	216	48	74	42	(480)	94	5
As at Dec. 31, 2015	95	6,091	1,484	3,265	1,208	351	360	12,854
Additions	**2**	**-**	**-**	**1**	**-**	**353**	**2**	**358**
Additions - finance lease	**-**	**-**	**-**	**-**	**7**	**-**	**-**	**7**
Disposals	**(1)**	**-**	**(3)**	**(1)**	**(1)**	**-**	**(3)**	**(9)**

Impairment charges - Wintering Hills *(Note 4)*	**-**	**-**	**-**	**(28)**	**-**	**-**	**-**	**(28)**
Other *(Note 6)*	**-**	**-**	**-**	**-**	**-**	**-**	**(1)**	**(1)**
Revisions and additions to decommissioning and restoration costs	**-**	**14**	**12**	**4**	**36**	**-**	**5**	**71**
Retirement of assets	**-**	**(96)**	**(3)**	**(14)**	**(6)**	**-**	**(3)**	**(122)**
Change in foreign exchange rates	**(1)**	**(38)**	**(16)**	**(10)**	**(3)**	**(13)**	**(4)**	**(85)**
Reclassification to held for sale *(Note 4)*	**-**	**-**	**-**	**(67)**	**-**	**-**	**-**	**(67)**
Transfers [2]	**-**	**(95)**	**51**	**62**	**24**	**(284)**	**37**	**(205)**
As at Dec. 31, 2016	**95**	**5,876**	**1,525**	**3,212**	**1,265**	**407**	**393**	**12,773**
Accumulated depreciation								
As at Dec. 31, 2014	-	2,941	993	713	544	-	103	5,294
Depreciation	-	279	85	107	60	-	14	545
Retirement of assets	-	(96)	(15)	(12)	(7)	-	(4)	(134)
Disposals	-	-	(8)	-	-	-	-	(8)
Disposals - Poplar Creek *(Note 4)*	-	-	(202)	-	-	-	-	(202)
Change in foreign exchange rates	-	155	21	2	7	-	1	186
Transfers	-	1	(1)	-	-	-	-	-
As at Dec. 31, 2015	-	3,280	873	810	604	-	114	5,681
Depreciation	-	284	118	127	59	-	19	607
Retirement of assets	-	(85)	(4)	(7)	(2)	-	(3)	(101)
Disposals	-	-	(1)	-	(1)	-	-	(2)
Change in foreign exchange rates	-	(28)	(10)	-	(1)	-	-	(39)
Reclassification to held for sale *(Note 4)*	-	-	-	(6)	-	-	-	(6)
Transfers [2]	-	(239)	51	(2)	-	-	(1)	(191)
As at Dec. 31, 2016	**-**	**3,212**	**1,027**	**922**	**659**	**-**	**129**	**5,949**
Carrying amount								
As at Dec. 31, 2014	82	2,862	876	2,169	615	341	168	7,113
As at Dec. 31, 2015	95	2,811	611	2,455	604	351	246	7,173
As at Dec. 31, 2016	**95**	**2,664**	**498**	**2,290**	**606**	**407**	**264**	**6,824**

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

(2) Net transfers of $14 million relate to the transfer of gas equipment to finance lease receivables.

The Corporation capitalized $16 million of interest to PP&E in 2016 (2015 - $9 million) at a weighted average rate of 5.93 per cent (2015 – 5.83 per cent).

Finance lease additions in 2016 and 2015 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2016 was $76 million (2015 - $81 million).

17. Goodwill

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

As at Dec. 31	**2016**	2015
Hydro	**259**	259
Wind and Solar	**175**	176
Energy Marketing	**30**	30
Total goodwill	**464**	465

During 2015, the Corporation systemized allocations of certain costs to each fuel type within the broad generation segment. Accordingly, the Corporation disaggregated the generation segment into distinct generation segments as reportable segments. Accordingly, the Corporation re-allocated goodwill on a relative fair value basis in 2015. The Corporation allocated goodwill of the previous Canadian Renewables and Alberta Merchant group of CGUs to the Hydro and Wind and Solar segments and the previous U.S. Operations goodwill to the Wind and Solar segment on the basis of management's allocations for monitoring and performance measurement purposes. There were no changes made to the Energy Marketing goodwill.

For purposes of the 2016 and 2015 annual goodwill impairment review, the Corporation determined the recoverable amounts of the test units by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

The key assumption impacting the determination of fair value for the wind and solar and hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2016 models ranged between $32 to $301 per MWh during the forecast period (2015 - $26 to $311 per MWh). Discount rates used for the goodwill impairment calculation in 2016 ranged from 5.5 per cent to 6.0 per cent (2015 – 5.3 per cent to 6.5 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

18. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2014	178	206	186	34	604
Additions	-	1	-	25	26
Acquisitions *(Note 4)*	-	-	37	-	37
Retirements	-	(1)	-	-	(1)
Change in foreign exchange rates	-	8	-	-	8
Transfers	-	42	-	(44)	(2)
As at Dec. 31, 2015	178	256	223	15	672
Additions	**-**	**-**	**-**	**21**	**21**
Additions - capital lease	**-**	**3**	**-**	**-**	**3**
Retirements	**-**	**(3)**	**-**	**-**	**(3)**
Change in foreign exchange rates	**-**	**(1)**	**-**	**(1)**	**(2)**
Transfers	**-**	**13**	**-**	**(11)**	**2**
As at Dec. 31, 2016	**178**	**268**	**223**	**24**	**693**
Accumulated amortization					
As at Dec. 31, 2014	106	124	43	-	273
Amortization	3	20	9	-	32
Change in foreign exchange rates	-	3	-	-	3
Transfers	-	(5)	-	-	(5)
As at Dec. 31, 2015	109	142	52	-	303
Amortization	**6**	**24**	**8**	**-**	**38**
Retirements	**-**	**(3)**	**-**	**-**	**(3)**
As at Dec. 31, 2016	**115**	**163**	**60**	**-**	**338**
Carrying amount					
As at Dec. 31, 2014	72	82	143	34	331
As at Dec. 31, 2015	69	114	171	15	369
As at Dec. 31, 2016	**63**	**105**	**163**	**24**	**355**

19. Other Assets

The components of other assets are as follows:

As at Dec. 31	**2016**	2015
Deferred licence fees	**15**	16
Project development costs	**46**	42
Deferred service costs	**16**	17
Mississauga long-term receivable *(Note 4)*	**116**	-
Long-term prepaids and other	**44**	52
Keephills Unit 3 transmission deposit	**5**	6
Total other assets	**242**	133

Deferred license fees consist primarily of licenses 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 licenses relate.

Project development costs are primarily comprised of the Corporation's Sundance 7 and Dunvegan projects in Alberta. In December 2015, the Corporation repurchased its partner's 50 per cent share in TAMA Power, the jointly controlled entity developing the Sundance 7 project, for consideration of $10 million, payable in five years and an option for its partner to re-enter the development projects of TAMA Power at accumulated cost during this period.

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.

Mississauga long-term receivable relates to amounts recognized as a result of entering into the new contract. Fixed monthly payments are to be received until Dec. 31, 2018. See Note 4 for further details.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Bill commitments presented in Note 32.

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 five years to 2021, as long as certain performance criteria are met.

20. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2014	305	51	356
Liabilities incurred	6	58	64
Liabilities acquired	7	-	7
Liabilities settled	(24)	(14)	(38)
Liabilities disposed	(11)	(1)	(12)
Accretion	20	1	21
Revisions in estimated cash flows	1	71	72
Revisions in discount rates	(89)	-	(89)
Reversals	-	(2)	(2)
Change in foreign exchange rates	18	1	19
Balance, Dec. 31, 2015	233	165	398
Liabilities incurred	11	12	23
Liabilities settled	(23)	(36)	(59)
Accretion	19	1	20
Revisions in estimated cash flows	12	5	17
Revisions in discount rates	44	-	44
Reversals	-	(96)	(96)
Change in foreign exchange rates	(3)	(1)	(4)
Balance, Dec. 31, 2016	**293**	**50**	**343**

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2015	233	165	398
Current portion	30	136	166
Non-current portion	203	29	232
Balance, Dec. 31, 2016	**293**	**50**	**343**
Current portion	**27**	**12**	**39**
Non-current portion	**266**	**38**	**304**

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 $1.1 billion, which will be incurred between 2017 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2016, the Corporation had provided a surety bond in the amount of US$139 million (2015 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2016, the Corporation had provided letters of credit in the amount of $117 million (2015 - $115 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Other Provisions

Other provisions include amounts 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 and for vacant leased premises. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2023.

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.

During 2015, the Corporation recorded a significant adjustment to other provisions, relating to the force majeure claim at Keephills 1. However, on Nov. 18, 2016, force majeure relief was granted to the Corporation and accordingly approximately $94 million was reversed during the last quarter of 2016 as disclosed in Note 4(B).

21. Credit Facilities, Long-Term Debt, and Finance Lease Obligations

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at Dec. 31	2016			2015		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**-**	**-**	**-**	315	315	3.1%
Debentures	**1,045**	**1,051**	**6.0%**	1,044	1,051	6.0%
Senior notes[3]	**2,151**	**2,158**	**5.0%**	2,221	2,221	4.9%
Non-recourse[4]	**1,038**	**1,048**	**4.5%**	766	773	4.5%
Other[5]	**54**	**54**	**9.2%**	67	67	9.3%
	4,288	**4,311**		4,413	4,427	
Finance lease obligations	**73**			82		
	4,361			4,495		
Less: current portion of long-term debt	**(623)**			(72)		
Less: current portion of finance lease obligations	**(16)**			(15)		
Total current long-term debt and finance lease obligations	**(639)**			(87)		
Total credit facilities, long-term debt, and finance lease obligations	**3,722**			4,408		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) U.S. face value at Dec. 31, 2016 - US$1.6 billion (Dec. 31, 2015 - US$1.6 billion).
(4) Includes US$53 million at Dec. 31, 2016 (Dec. 31, 2015 - US$59 million).
(5) Includes US$29 million at Dec. 31, 2016 (Dec. 31, 2015 - US$36 million) of tax equity financing.

Credit facilities 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. 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 in committed bilateral credit facilities which expire in 2018 and a US$200 million committed bilateral credit facility expiring in 2020.

During 2016, the Corporation:
§ paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian Assets that closed Jan. 6, 2016 (see Note 4);
§ extended the four-year revolving $1.5 billion committed syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018, respectively, with key terms and covenants unchanged; and
§ extended the four-year US$200 million bilateral credit facility to 2020. The amount available was reduced from US$300 million to US$200 million. The remaining key terms and covenants were unchanged.

Of the $2.0 billion (2015 - $2.2 billion) of committed credit facilities, $1.4 billion (2015 - $1.3 billion) is not drawn. The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, TransAlta also has $305 million of available cash and cash equivalents.

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2019 to 2030.

Senior notes bear interest at rates ranging from 1.90 per cent to 6.90 per cent and have maturity dates ranging from 2017 to 2040.

On Jan. 15, 2015, the Corporation's US$500 million 4.75 per cent senior notes matured and were paid out using existing liquidity.

A total of US$630 million (2015 - US$580 million) of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2017 to 2032 and bear interest at rates ranging from 2.95 per cent to 7.31 per cent.

During 2016:
§ the Corporation's $27 million 5.69 per cent non-recourse debenture matured and was paid out using existing liquidity;
§ the Corporation's subsidiary New Richmond Wind L.P. issued a non-recourse bond in the amount of $159 million, bearing interest at 3.963 per cent, with principal and interest payable semi-annually, and maturing on June 30, 2032 (see Note 4);
§ the Corporation made a scheduled semi-annual $4.2 million principal payment on the New Richmond Wind L.P. bond;
§ the Corporation made scheduled semi-annual principal payments of approximately $35 million on the Melancthon-Wolfe Wind L.P. bond;
§ the Corporation's subsidiary TAPC Holdings L.P. issued a non-recourse bond in the amount of $202.5 million, bearing a variable interest rate at the Canadian Dollar Offered Rate plus 395 basis points, with principal and interest payable quarterly, maturing on Dec. 31, 2030 (see Note 4), and;
§ early redeemed $10 million of non-recourse bonds, which resulted in a $1 million loss recognized in interest expense.

During 2015:
§ the Corporation and its partner issued non-recourse bonds secured by their jointly owned Pingston facility. The Corporation's share of gross proceeds was $45 million. The non-recourse bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million non-recourse debenture bearing interest at 5.28 per cent related to the Pingston facility.
§ the Corporation's $120 million 5.33 per cent non-recourse debentures matured and were paid out using existing liquidity. The Corporation also closed the acquisition of solar assets (see Note 4) and assumed approximately US$42 million of non-recourse variable rate debt, of which approximately US$32 million is hedged to a fixed rate of 1.7 per cent.

§ the Corporation's indirect wholly-owned subsidiary Melancthon-Wolfe Wind L.P. issued a non-recourse bond in the amount of $442 million, bearing interest at 3.834 per cent, with principal and interest payable semi-annually in blended payments until maturity on Dec. 31, 2028.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financing assumed in the Lakeswind wind acquisition (see Note 4).

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2016, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt and Security

Non-recourse debentures of $193 million (2015 - $230 million) issued by the Corporation's subsidiary, CHD, include restrictive covenants requiring the cash proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures.

Other non-recourse debt of $845 million in total (2015 - $536 million) is subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by certain facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. At Dec. 31, 2016, $24 million of cash was subject to these financial restrictions. Non-recourse debts of $644 million are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes renewable generation facilities with total carrying amounts of $956 million at Dec. 31, 2016 (2015 - $798 million). A non-recourse bond of approximately $201 million is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

C. Principal Repayments

	2017	**2018**	**2019**	**2020**	**2021**	**2022 and thereafter**	**Total**
Principal repayments[1]	623	959	461	460	63	1,745	**4,311**

(1) Excludes impact of derivatives.

D. Finance Lease Obligations

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

As at Dec. 31	**2016**		2015	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**19**	**19**	18	18
Second to fifth years inclusive	**44**	**39**	49	44
More than five years	**21**	**15**	29	20
	84	**73**	96	82
Less: interest costs	**11**	**-**	14	-
Total finance lease obligations	**73**	**73**	82	82
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease obligations	**16**		15	
Long-term portion of finance lease obligations	**57**		67	
	73		82	

E. Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2016 was $566 million (2015 - $575 million) with no (2015 - nil) amounts exercised by third parties under these arrangements.

22. Defined Benefit Obligation and Other Long-Term Liabilities

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

As at Dec. 31	**2016**	2015
Defined benefit obligation *(Note 27)*	**208**	222
Deferred coal revenues	**62**	60
Long-term incentive accruals *(Note 26)*	**14**	8
Other	**46**	58
Total	**330**	348

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint operation partner for future coal deliveries. These amounts are being amortized into revenue over the life of the coal supply agreement, since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

Other includes $10 million (2015 - $11 million) relating to a reimbursement received for costs of the New Richmond terminal station, which is being amortized to revenue over the term of the related PPA.

23. 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	2016		2015	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**284.0**	**3,077**	275.0	3,001
Issued under the dividend reinvestment and share purchase plan	**3.9**	**18**	9.0	76
	287.9	**3,095**	284.0	3,077
Amounts receivable under Employee Share Purchase Plan	**-**	**(1)**	-	(2)
Issued and outstanding, end of year	**287.9**	**3,094**	284.0	3,075

B. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which 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 it was last approved on April 22, 2016. The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. 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" (as defined in the Shareholder Rights Plan), where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

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

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan provided eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component).

The Corporation suspended the Premium Dividend™ Component of the Plan following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remained effective in accordance with their current terms. On Jan. 14, 2016, the Corporation announced the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP"), in order to stop shareholder dilution.

On Jan. 1, 2016, 3.9 million common shares were issued for dividends reinvested.

D. Earnings per Share

Year ended Dec. 31	2016	2015	2014
Net earnings (loss) attributable to common shareholders	**117**	(24)	141
Basic and diluted weighted average number of common shares outstanding (millions)	**288**	280	273
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.41**	(0.09)	0.52

E. Dividends

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually, as part of a plan to maximize the Company's long-term financial flexibility.

On Oct. 17, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2017.

On Dec. 19, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on April 1, 2017.

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

24. Preferred Shares

A. Issued and Outstanding

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

As at Dec. 31	2016		2015	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	10.2	248	12.0	293
Series B	1.8	45	-	-
Series C	11.0	269	11.0	269
Series E	9.0	219	9.0	219
Series G	6.6	161	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares conversion

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2016.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annualized fixed dividend rate of 2.539 per cent, and will reset every quarter.

II. Preferred Share Series Information

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

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2016, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next Conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.79543	March 31, 2021	2.03	B
B	Floating	0.47608	March 31, 2021	2.03	A
C	Fixed	1.15	June 30, 2017	3.10	D
D	Floating	-	-	3.10	C
E	Fixed	1.25	Sept. 30, 2017	3.65	F
F	Floating	-	-	3.65	E
G	Fixed	1.325	Sept. 30, 2019	3.80	H
H	Floating	-	-	3.80	G

B. Dividends

The following table summarizes the preferred share dividends declared in 2016, 2015, and 2014:

	Total dividends declared ($)		
Series	**2016**	2015	2014
A	10	14	14
B	1	-	-
C	16	13	13
E	14	11	11
G	11	8	3
Total for the year	**52**	46	41

On Dec. 19, 2016, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.15651 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2017.

25. Accumulated Other Comprehensive Income

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

	2016	2015
Currency translation adjustment		
Opening balance, Jan. 1	**52**	(19)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(71)**	237
(Gains) losses on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[2]	**18**	(166)
Balance, Dec. 31	**(1)**	52
Cash flow hedges		
Opening balance, Jan. 1	**350**	173
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[3]	**106**	177
Balance, Dec. 31	**456**	350
Employee future benefits		
Opening balance, Jan. 1	**(46)**	(50)
Net actuarial gains on defined benefit plans, net of tax[4]	**8**	4
Balance, Dec. 31	**(38)**	(46)
Other		
Opening balance, Jan. 1	**(3)**	-
Intercompany available-for-sale investments	**(15)**	(3)
Balance, Dec. 31	**(18)**	(3)
Accumulated other comprehensive income	**399**	353

(1) Net of income tax expense of 11 for the year ended Dec. 31, 2016 (2015 - nil).

(2) Net of income tax expense of 5 for the year ended Dec. 31, 2016 (2015 - 8 expense).

(3) Net of income tax expense of 51 for the year ended Dec. 31, 2016 (2015 - 89 expense).

(4) Net of income tax expense of 4 for the year ended Dec. 31, 2016 (2015 - nil).

26. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

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

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

The pre-tax compensation expense related to PSUs and RSUs in 2016 was $17 million (2015 - $3 million reversal, 2014 - $8 million expense), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $3 million in 2016 (2015 - $2 million reversal, 2014 - nil).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance. The expense recognized relating to this grant during 2016 was less than $1 million.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2016 are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	**Number of options at Dec. 31, 2016** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 6.00	1.1	6.1	5.93
22.00 - 30.00[(1)]	0.6	3.1	23.60
31.00 - 48.00[(1)]	0.5	1.1	34.35
5.00 - 48.00	**2.2**	**4.2**	**28.93**

(1) Options currently exerciseable.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation extended interest-free loans (up to 30 per cent of an employee's base salary) to employees below executive level and allowed for payroll deductions over a three-year period to repay the loan. Executives were not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchased 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 were handled in the same manner. At Dec. 31, 2016, amounts receivable from employees under the plan totaled $1 million (2015 - $2 million).

On Jan. 14, 2016, the Corporation suspended its employee share purchase plan.

27. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned.

The latest actuarial valuations for accounting purposes of the Canadian and U.S. pension plans were at Dec. 31, 2015 and Jan. 1, 2016, respectively. The latest actuarial valuation for accounting purposes of the Highvale pension plan was at Dec. 31, 2013. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2016.

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 U.S. The latest actuarial valuation for funding purposes of the Canadian registered plans was completed in early 2016 with an effective date of Dec. 31, 2015. The latest actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2016. As permitted by the regulators, the TransAlta Corporation pension plan uses a letter of credit to secure the required solvency special payments. The Corporation posted a letter of credit in the amount of $75 million for the annual period commencing in July 2016.

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 $73 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 valuations for accounting purposes of the Canadian and U.S. plans were as at Dec. 31, 2016 and Jan. 1, 2016, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2016.

The Corporation provides several defined contribution plans, including a U.S. 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

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

Year ended Dec. 31, 2016	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**2**	**11**
Administration expenses	**2**	**-**	**-**	**2**
Interest cost on defined benefit obligation	**21**	**3**	**1**	**25**
Interest on plan assets	**(16)**	**-**	**-**	**(16)**
Curtailment and amendment gain	**-**	**-**	**-**	**-**

Defined benefit expense	**14**	**5**	**3**	**22**
Defined contribution expense	**15**	**-**	**-**	**15**
Net expense	**29**	**5**	**3**	**37**

Year ended Dec. 31, 2015	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	-	-	(16)
Curtailment and amendment gain[(1)]	-	(5)	(3)	(8)
Defined benefit expense	14	-	-	14
Defined contribution expense	21	-	-	21
Net expense	35	-	-	35

(1) Relates to the reduction in the number of employees associated with the restructuring intative described in Note 4(L).

Year ended Dec. 31, 2014	Registered	Supplemental	Other	Total
Current service cost	6	2	2	10
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	23	4	1	28
Interest on plan assets	(18)	-	-	(18)
Defined benefit expense	13	6	3	22
Defined contribution expense	20	-	-	20
Net expense	33	6	3	42

C. Status of Plans

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

As at Dec. 31, 2016	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**423**	**10**	**-**	**433**
Present value of defined benefit obligation	**(554)**	**(82)**	**(27)**	**(663)**
Funded status - plan deficit	**(131)**	**(72)**	**(27)**	**(230)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(15)**	**(6)**	**(1)**	**(22)**
Other long-term liabilities	**(116)**	**(66)**	**(26)**	**(208)**
Total amount recognized	**(131)**	**(72)**	**(27)**	**(230)**

As at Dec. 31, 2015	Registered	Supplemental	Other	Total
Fair value of plan assets	429	9	-	438
Present value of defined benefit obligation	(566)	(80)	(32)	(678)
Funded status - plan deficit	(137)	(71)	(32)	(240)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(11)	(5)	(2)	(18)
Other long-term liabilities	(126)	(66)	(30)	(222)
Total amount recognized	(137)	(71)	(32)	(240)

D. Plan Assets

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

	Registered	**Supplemental**	**Other**	**Total**
Fair value of plan assets as at Dec. 31, 2014	427	8	-	435
Interest on plan assets	16	-	-	16
Net return on plan assets	6	-	-	6

Contributions	12	7	1	20
Benefits paid	(36)	(6)	(1)	(43)
Administration expenses	(2)	-	-	(2)
Effect of translation on U.S. plans	6	-	-	6
Fair value of plan assets as at Dec. 31, 2015	**429**	**9**	**-**	**438**
Interest on plan assets	**16**	**-**	**-**	**16**
Net return on plan assets	**10**	**-**	**-**	**10**
Contributions	**11**	**6**	**1**	**18**
Benefits paid	**(40)**	**(5)**	**(1)**	**(46)**
Administration expenses	**(2)**	**-**	**-**	**(2)**
Effect of translation on U.S. plans	**(1)**	**-**	**-**	**(1)**
Fair value of plan assets as at Dec. 31, 2016	**423**	**10**	**-**	**433**

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

Year ended Dec. 31, 2016	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**-**	**76**	**-**	**76**
U.S.	**-**	**30**	**-**	**30**
International	**-**	**120**	**-**	**120**
Private	**-**	**-**	**2**	**2**
Bonds				
AAA	**-**	**47**	**-**	**47**
AA	**-**	**58**	**-**	**58**
A	**-**	**55**	**-**	**55**
BBB	**1**	**22**	**-**	**23**
Below BBB	**-**	**5**	**-**	**5**
Money market and cash and cash equivalents	**3**	**14**	**-**	**17**
Total	**4**	**427**	**2**	**433**

Year ended Dec. 31, 2015	Level I	Level II	Level III	Total
Equity securities				
Canadian	-	70	-	70
U.S.	-	32	-	32
International	-	120	-	120
Private	-	-	3	3
Bonds				
AAA	-	53	-	53
AA	-	57	-	57
A	1	60	-	61
BBB	1	21	-	22
Below BBB	-	4	-	4
Money market and cash and cash equivalents	4	12	-	16
Total	6	429	3	438

Plan assets do not include any common shares of the Corporation at Dec. 31, 2016 and Dec. 31, 2015. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2016 (2015 - $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, 2014	565	86	30	681
Current service cost	7	2	2	11
Interest cost	21	3	1	25
Benefits paid	(36)	(6)	(1)	(43)
Actuarial gain arising from demographic assumptions	(1)	-	-	(1)
Actuarial loss arising from financial assumptions	3	2	2	7
Actuarial gain arising from experience adjustments	-	(2)	(2)	(4)
Curtailment and amendment	-	(5)	(3)	(8)
Effect of translation on U.S. plans	7	-	3	10
Present value of defined benefit obligation as at Dec. 31, 2015	**566**	**80**	**32**	**678**
Current service cost	**7**	**2**	**2**	**11**
Interest cost	**21**	**3**	**1**	**25**
Benefits paid	**(40)**	**(5)**	**(1)**	**(46)**
Actuarial loss arising from demographic assumptions	**(1)**	**-**	**(4)**	**(5)**
Actuarial gain arising from financial assumptions	**2**	**-**	**-**	**2**
Actuarial (gain) loss arising from experience adjustments	**-**	**2**	**(2)**	**-**
Effect of translation on U.S. plans	**(1)**	**-**	**(1)**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2016	**554**	**82**	**27**	**663**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2016 is 13.6 years.

F. Contributions

The expected employer contributions for 2017 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**15**	**6**	**1**	**22**

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, 2016			As at Dec. 31, 2015		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.7**	**3.6**	**3.7**	3.8	3.6	3.8
Rate of compensation increase	**2.9**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.9**[(1)]	-	-	7.8[(3)]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**-**	-	-	5.0
Benefit cost for the year						
Discount rate	**3.8**	**3.8**	**3.8**	3.8	3.8	3.8
Rate of compensation increase	**3.0**	**3.0**	**-**	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	**-**	**-**	**7.8**[(2)]	-	-	7.5[(4)]
Dental care cost escalation	**-**	**-**	**4.0**	-	-	4.0
Provincial health care premium escalation	**-**	**-**	**5.0**	-	-	5.0

(1) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2024 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.
(3) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2024 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.
(4) Post- and Pre 65 rates: decreasing gradually to 5% by 2019-2020 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.

H. Sensitivity Analysis

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

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2016	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**73**	**12**	**2**	**3**	**1**
1% increase in the salary scale	**9**	**1**	**-**	**-**	**-**
1% increase in the health care cost trend rate	**-**	**-**	**2**	**-**	**-**
10% improvement in mortality rates	**17**	**2**	**-**	**1**	**-**

28. Joint Arrangements

Joint arrangements at Dec. 31, 2016 included the following:

Joint operations	**Segment**	**Ownership** *(per cent)*	**Description**
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
Wintering Hills [(1)]	Wind	51	Wind generation facility in Alberta operated by TransAlta
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

(1) Classified as held for sale as at Dec. 31, 2016 (See Note 4(E)).

29. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2016**	2015	2014
(Use) source:			
Accounts receivable	**(23)**	(77)	59
Prepaid expenses	**5**	(3)	(1)
Income taxes receivable	**(4)**	1	1
Inventory	**11**	(9)	7
Accounts payable, accrued liabilities, and provisions	**81**	(152)	8
Income taxes payable	**3**	(2)	(1)
Change in non-cash operating working capital	**73**	(242)	73

30. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	**2016**	2015	**Increase/ (decrease)**
Long-term debt[(1)]	**4,361**	4,495	**(134)**
Equity			
Common shares	**3,094**	3,075	**19**
Preferred shares	**942**	942	**-**
Contributed surplus	**9**	9	**-**
Deficit	**(933)**	(1,018)	**85**
Accumulated other comprehensive income	**399**	353	**46**
Non-controlling interests	**1,152**	1,029	**123**
Less: available cash and cash equivalents[(2)]	**(305)**	(54)	**(251)**
Less: fair value asset of hedging instruments on long-term debt[(3)]	**(163)**	(190)	**27**
Total capital	**8,556**	8,641	**(85)**

(1) Includes finance lease obligations, amounts outstanding under credit facilities, tax equity liability, and current portion of long-term debt.

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

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

In 2016, the Corporation focused on raising non-recourse debt to fund upcoming corporate debt maturities. The Corporation's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2015 and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios, and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

The Corporation has an investment grade credit rating from S&P (stable outlook), DBRS (negative outlook), and Fitch (negative outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Strengthening the Corporation's financial position allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results, and provides the Corporation with better access to capital markets through commodity and credit cycles.

As at Dec. 31	**2016**	2015	Target
Comparable funds from operations to adjusted interest coverage (times)	**3.8**	3.8	4 to 5
Adjusted comparable funds from operations to adjusted net debt (%)	**17.0**	15.2	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization (times)	**3.8**	5.0	3.0 to 3.5

Comparable Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as comparable FFO plus interest on debt (net of capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares. Comparable FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. Comparable FFO to adjusted interest coverage in 2016 is consistent with 2015. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted Comparable FFO to Adjusted Net Debt is calculated as comparable FFO less 50 per cent of dividends paid on preferred shares divided by net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents and including fair value assets of hedging instruments on debt). Adjusted comparable FFO to adjusted net debt increased in 2016 compared to 2015 due to the increase in comparable FFO, and lower debt due to repayments and the strengthening of the Canadian dollar in 2016. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA") is calculated as net debt divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation, and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. Adjusted net debt to comparable EBITDA in 2016 improved compared to 2015 due to the lower debt balance due to repayments and the strengthening of the Canadian dollar, and higher comparable EBITDA. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2016, the Corporation continued to strengthen its financial position and reduce debt; using proceeds from the dropdown of the Canadian Assets to pay out the credit facility balance, and reducing the Corporation's dividend to $0.16 per common share on an annualized basis from $0.72 per common share.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

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

For the year ended Dec. 31, 2016 and 2015, net cash outflows, are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	**2016**	2015	**Increase (decrease)**
Cash flow from operating activities	**744**	432	312
Change in non-cash working capital	**(73)**	242	(315)
Cash flow from operations before changes in working capital	**671**	674	(3)
Dividends paid on common shares	**(69)**	(124)	55

Dividends paid on preferred shares	**(42)**	(46)	4
Distributions paid to subsidiaries' non-controlling interests	**(151)**	(99)	(52)
Property, plant, and equipment expenditures[1]	**(358)**	(476)	118
Acquisitions	**-**	(101)	101
Outflow	**51**	(172)	223

(1) Includes growth capital associated with the South Hedland power project.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2016, $1.4 billion (2015 - $1.3 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. TransAlta is focused on replacing additional maturing recourse debt with debt secured by contracted cash flows.

During 2016, the Corporation paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian assets that closed Jan. 6, 2016, (see Note 4), extended the Corporation's committed syndicated credit facility by one year to 2020, extended four bilateral credit facilities to 2018 and 2020, paid out a matured $27 million non-recourse debenture using existing liquidity, the Corporation's subsidiary New Richmond Wind L.P. issued a $159 million non-recourse bond, the Corporation's indirect wholly-owned subsidiary TAPC Holdings L.P. issued a $202.5 million non-recourse bond, and converted 1.8 million of the Series A Shares into Series B Shares. For further details see Notes 21 and 24.

During 2015, the Corporation repaid US$500 million of senior notes that matured; completed a refinancing at the Pingston facility for gross proceeds of $45 million; entered into an investment agreement to dropdown the Australian portfolio to TransAlta Renewables for gross proceeds of $217 million; and issued $442 million of senior secured amortizing debt through Melancthon Wolfe Wind LP with proceeds partially used to repay the $120 million CHD maturity.

31. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2016 are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	64.0	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 and members of the senior management team that report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	2016	2015	2014
Total compensation	**20**	9	13
Comprised of:			
Short-term employee benefits	**8**	8	8
Post-employment benefits	**2**	2	2
Termination benefits	**-**	1	-
Share-based payments	**10**	(2)	3

32. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total

Natural gas, transportation, and other purchase contracts	40	13	6	5	5	100	**169**
Transmission	9	11	8	8	4	3	**43**
Coal supply and mining agreements	163	48	49	51	52	472	**835**
Long-term service agreements	79	29	24	41	30	51	**254**
Non-cancellable operating leases[1]	7	7	7	7	7	68	**103**
Growth	181	5	1	-	-	-	**187**
TransAlta Energy Bill	6	6	6	6	6	12	**42**
Total	**485**	**119**	**101**	**118**	**104**	**706**	**1,633**

(1) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.

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

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 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, and certain other mining royalty agreements. Some of these agreements and the related commitments may be impacted by the cessation of coal-fired emissions from the Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

D. Long-Term Service Agreements

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

E. Non-Cancellable Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment and commitments for water rights and transmission tower right of ways.

During the year ended Dec. 31, 2016, $9 million (2015 - $9 million, 2014 - $10 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2016 and 2015 were less than $1 million (2015 - less than $1 million). No contingent rental payments were made in respect of these operating leases.

F. Growth

Commitments for growth primarily relate to the construction of the South Hedland power project.

G. TransAlta Energy Bill Commitments

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining 10 year life of the Centralia coal plant to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Dec. 31, 2016, the Corporation has funded approximately US$22 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation is participating in a line loss rule proceeding (the "LLRP") which is currently before the AUC. The AUC determined that it had the ability to retroactively adjust line loss rates beginning in 2006 and has directed the Alberta Electric System Operator (the "AESO"), among other actions, to perform such calculations. The various decisions by the AUC are subject to appeal and challenge. The Corporation may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP remains uncertain and the potential exposure, if any, cannot be calculated with any degree of certainty until the retroactive calculations are made available. The AESO expects retroactive calculations to be available mid-2017, at the earliest. As a result, no provision

has been recorded. Certain PPAs for the Corporation's Alberta facilities provide for the pass through of these types of transmission charges to the Corporation's buyers.

33. Segment Disclosures

A. Description of Reportable Segments

The Corporation has eight reportable segments as described in Note 1. During 2016, the Corporation disaggregated presentation of the previous Gas reportable segment into its two operating segments; Canadian Gas and Australian Gas. See Note 3 for further details.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2016	**Canadian Coal**	**U.S. Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**1,048**	**354**	**402**	**119**	**272**	**126**	**76**	**-**	**2,397**
Fuel and purchased power	**451**	**281**	**185**	**20**	**18**	**8**	**-**	**-**	**963**
Gross margin	**597**	**73**	**217**	**99**	**254**	**118**	**76**	**-**	**1,434**
Operations, maintenance, and administration	**178**	**54**	**54**	**25**	**52**	**33**	**24**	**69**	**489**
Depreciation and amortization	**242**	**61**	**100**	**17**	**119**	**33**	**3**	**26**	**601**
Asset impairment	**-**	**-**	**-**	**-**	**28**	**-**	**-**	**-**	**28**
Restructuring provision	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1**	**1**
Taxes, other than income taxes	**13**	**4**	**1**	**1**	**8**	**3**	**-**	**1**	**31**
Net other operating income	**(2)**	**-**	**(191)**	**-**	**(1)**	**-**	**-**	**-**	**(194)**
Operating income (loss)	**166**	**(46)**	**253**	**56**	**48**	**49**	**49**	**(97)**	**478**
Finance lease income	**-**	**-**	**14**	**52**	**-**	**-**	**-**	**-**	**66**
Gain on sale of assets	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4**
Net interest expense									**(229)**
Foreign exchange loss									**(5)**
Earnings before income taxes									**314**

Year ended Dec. 31, 2015 (Restated - See Note 3)	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	372	454	114	250	116	49	-	2,267
Fuel and purchased power	441	316	204	20	19	8	-	-	1,008
Gross margin	471	56	250	94	231	108	49	-	1,259
Operations, maintenance, and administration	194	50	67	21	48	29	12	71	492
Depreciation and amortization	237	63	75	20	99	25	1	25	545
Asset impairment recovery	-	(2)	-	-	-	-	-	-	(2)
Restructuring provision	11	1	1	-	-	-	3	6	22
Taxes, other than income taxes	12	3	3	-	7	3	-	1	29
Net other operating (income) loss	(7)	-	-	-	-	(24)	56	-	25
Operating income (loss)	24	(59)	104	53	77	75	(23)	(103)	148
Finance lease income	-	-	9	49	-	-	-	-	58
Gain on sale of assets	-	-	262	-	-	-	-	-	262
Net interest expense									(251)
Foreign exchange gain									4
Earnings before income taxes									221

Year ended Dec. 31, 2014 *(Restated - see Note 3)*	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	1,023	423	573	118	247	131	108	-	2,623
Fuel and purchased power	492	255	299	23	14	9	-	-	1,092
Gross margin	531	168	274	95	233	122	108	-	1,531
Operations, maintenance, and administration	196	49	69	33	48	39	33	75	542
Depreciation and amortization	235	54	94	17	88	24	-	26	538

Asset impairment reversals	-	(5)	(1)	-	-	-	-	-	(6)
Taxes, other than income taxes	12	3	4	-	6	3	-	1	29
Net other operating (income) losses	(9)	-	-	-	-	(10)	5	-	(14)
Operating income (loss)	97	67	108	45	91	66	70	(102)	442
Finance lease income	-	-	7	42	-	-	-	-	49
Gain on sale of assets									2
Net interest expense									(254)
Earnings before income taxes									239

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2016 are $19 million (2015 - $20 million, 2014 - $21 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases, is included in revenues, and was $221 million for the year ended Dec. 31, 2016 (2014 - $230 million, 2014 - $219 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2016	**Canadian Coal**	**U.S. Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	-	-	-		**175**	**259**	**30**	**-**	**464**
PP&E	**3,069**	**428**	**414**	**527**	**1,856**	**503**	**2**	**25**	**6,824**
Intangible assets	**93**	**7**	**4**	**12**	**163**	**3**	**15**	**58**	**355**

As at Dec. 31, 2015	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	**-**	**-**	**-**	**-**	176	259	30	**-**	465
PP&E *(Restated - Note 3)*	3,148	484	512	472	2,043	486	2	26	7,173
Intangibles *(Restated - Note 3)*	92	6	2	13	176	3	17	60	369

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2016	**Canadian Coal**	**U.S. Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**159**	**15**	**11**	**107**	**16**	**43**	**-**	**7**	**358**
Intangible assets	**3**	**1**	**1**	**-**	**-**	**-**	**-**	**16**	**21**

Year ended Dec. 31, 2015	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E *(Restated - Note 3)*	179	13	19	204	13	43	1	4	476
Intangibles *(Restated - Note 3)*	6	-	-	-	-	-	3	17	26

Year ended Dec. 31, 2014	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E *(Restated - Note 3)*	206	14	58	148	13	42	1	5	487
Intangibles *(Restated - Note 3)*	2	-	-	7	-	-	8	17	34

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	**2016**	2015	2014
Depreciation and amortization expense on the Consolidated Statements of Earnings	**601**	545	538
Depreciation included in fuel and purchased power *(Note 5)*	**63**	59	56
Loss on disposal of property, plant, and equipment	**-**	1	1
Depreciation and amortization on the Consolidated Statements of Cash Flows	**664**	605	595

C. Geographic Information

I. Revenues

Year ended Dec. 31	**2016**	2015	2014

Canada	**1,828**	1,705	1,989
U.S.	**450**	448	516
Australia	**119**	114	118
Total revenue	**2,397**	2,267	2,623

II. Non-Current Assets

	Property, plant, and equipment		**Intangible assets**		**Other assets**		**Goodwill**	
As at Dec. 31	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Canada	**5,583**	5,902	**315**	328	**184**	79	**417**	417
U.S.	**714**	799	**28**	28	**42**	37	**47**	48
Australia	**527**	472	**12**	13	**16**	17	**-**	-
Total	**6,824**	7,173	**355**	369	**242**	133	**464**	465

D. Significant Customer

During the year ended Dec. 31, 2016, sales to two customers represented 25 per cent and 16 per cent, respectively, of the Corporation's total revenue (2015 - 13 per cent and 17 per cent).

34. Subsequent Events

A. Preferred Share Exchange

On Feb. 10, 2017, the Corporation announced that it would not proceed with the transaction previously announced on Dec. 19, 2016, pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares in the capital of the Corporation.

B. Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale closed March 1, 2017.

Exhibit 1

(Unaudited)

The information set out below is referred to as "unaudited" as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the "Consolidated Financial Statements".

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2016:

Earnings coverage on long-term debt supporting the Corporation's Shelf Prospectus

1.85 times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Exhibit 23.1

Ernst & Young LLP
2200, 215 2nd St SW
Calgary, AB T2P 1M4

Tel: +1 403 206 5000
Fax: +1 403 290 4265
ey.com/ca

Building a better working world

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated March 2, 2017 with respect to the consolidated financial statements of TransAlta Corporation as at December 31, 2016 and 2015 and for each of the years in the three year period ended December 31, 2016, and internal control over financial reporting as of December 31, 2016 of TransAlta Corporation, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) for 2016.

We also consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-72454 and No. 333-101470) pertaining to TransAlta Corporation's Share Option Plan

(2) Registration Statement (Form F-10 No. 333-215608) pertaining to the registration of Debt and Equity Securities of TransAlta Corporation

of our reports dated March 2, 2017, with respect to the consolidated financial statements of TransAlta Corporation as at December 31, 2016 and 2015 and for each of the years in the three year period ended December 31, 2016, and internal control over financial reporting as of December 31, 2016 of TransAlta Corporation, included as an exhibit to or incorporated by reference in the Annual Report (Form 40-F) of TransAlta Corporation for the year ended December 31, 2016.

/s/Ernst & Young LLP
Chartered Professional Accountants

Calgary, Alberta
March 2, 2017

A member firm of Ernst & Young Global Limited

Exhibit 31.1

Certifications

I, Dawn L. Farrell, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

March 3, 2017

/s/ Dawn L. Farrell
Dawn L. Farrell
President and Chief Executive Officer

Exhibit 31.2

Certifications

I, Donald Tremblay, certify that:

1. I have reviewed this annual report on Form 40-F of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

March 3, 2017

/s/ Donald Tremblay
Donald Tremblay
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dawn L. Farrell, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Dawn L. Farrell
Dawn L. Farrell
President and Chief Executive Officer

Dated: March 3, 2017

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of TransAlta Corporation (the "Company") on Form 40-F for the year ended December 31, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Donald Tremblay, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d), as applicable of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all materials respects, the financial condition and result of operations of the Company.

/s/ Donald Tremblay
Donald Tremblay
Chief Financial Officer

Dated: March 3, 2017

The foregoing certification is being furnished solely to accompany the Report pursuant to 18 U.S.C § 1350, and is not being filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not to be incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.